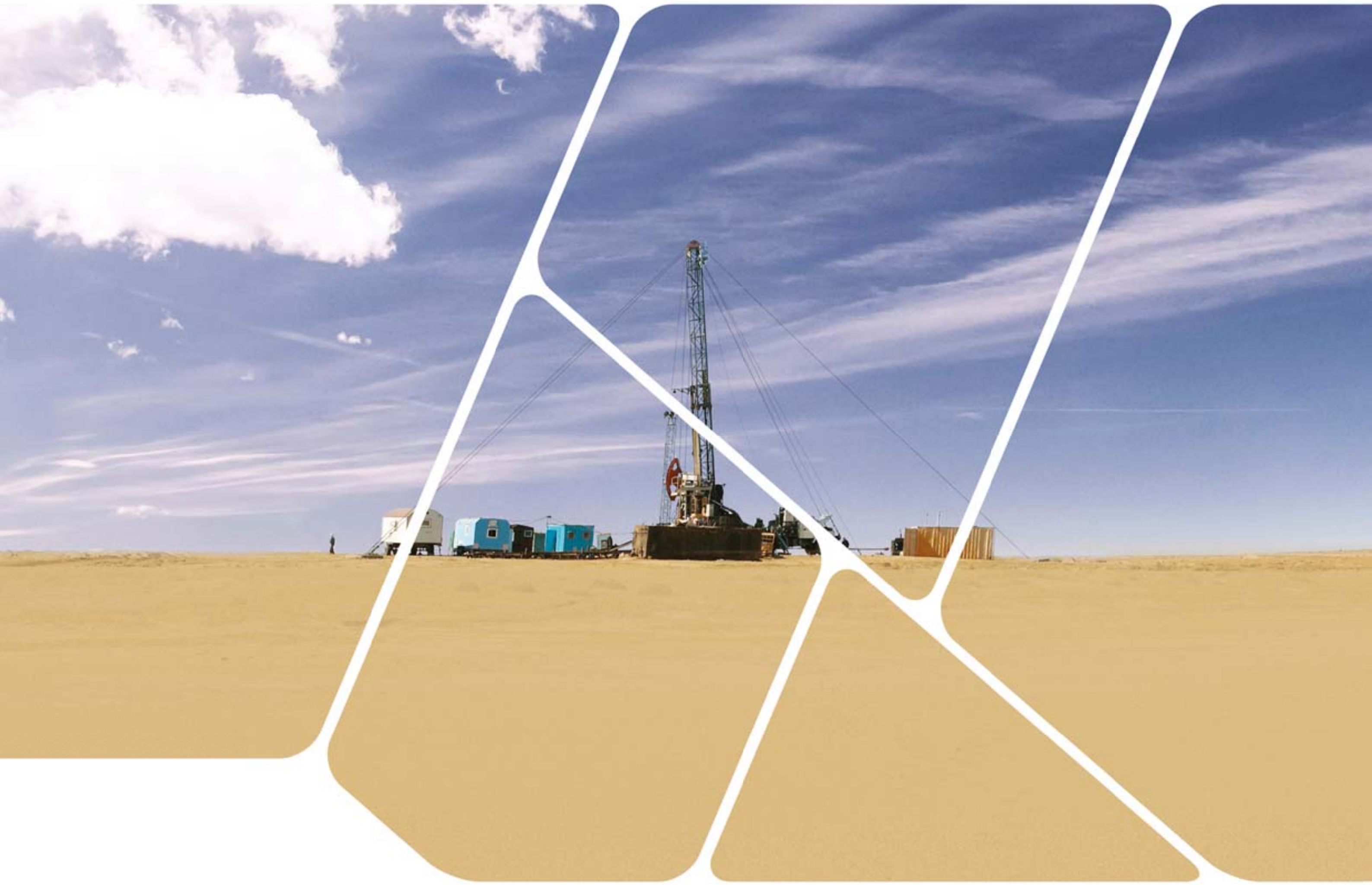


RESERVOIR ENGINEERING GRADUATE CERTIFICATE - *Week 6*

Well Testing and Well Test Analysis

A special course by IFP Training for REPSOL ALGERIA
Alger –December 04 to 08, 2016

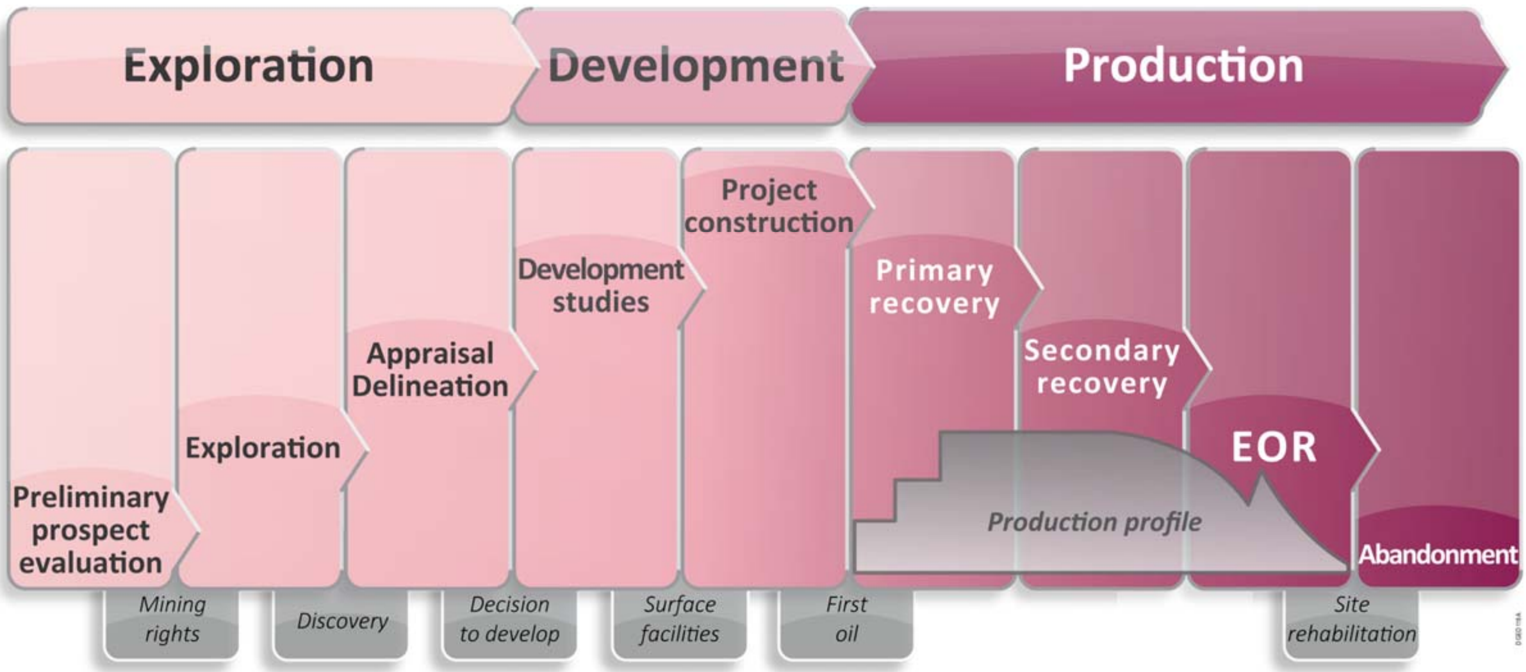
An IFP Training Course for REPSOL

Well Testing and Well Test Analysis

Instructor: Jacques Kuchly

IFP Training

E&P workflow – WT & WTA



Course contents

What is a well test?

- Well Test: A disturbance within the reservoir.
  - We disturb the reservoir: input
  - We observe the response : output
  - We infer the possible nature of the system

Disturbance → **System** → **Measurements**

- The answer is **ALWAYS** non-unique.
  - We use existing models to describe the system
  - And we compare the models response to te observed data

Objectives of a well test why?

- **Why are wells tested?**
  - To confirm the presence of hydrocarbons
  - To measure the initial reservoir pressure and temperature
  - To determine productivity
  - To determine permeability-thickness
  - To determine the completion efficiency
  - To identify the presence of nearby boundaries
  - To obtain fluid samples for analysis
  - To determine the reservoir size

- **Or maybe to do with the SEC:**

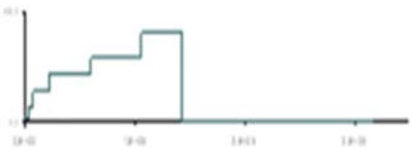
" … reserves are considered proved if the commercial productivity of the reservoir is supported by actual production or formation tests"

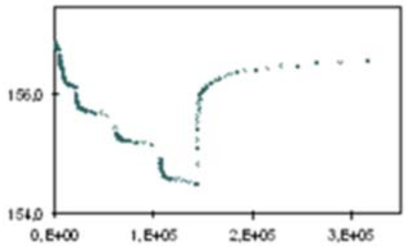
How ?

Interpretation methodology

- **Well Test:**
  - **A well rate variation creating a disturbance in the pressure regime within the reservoir.**

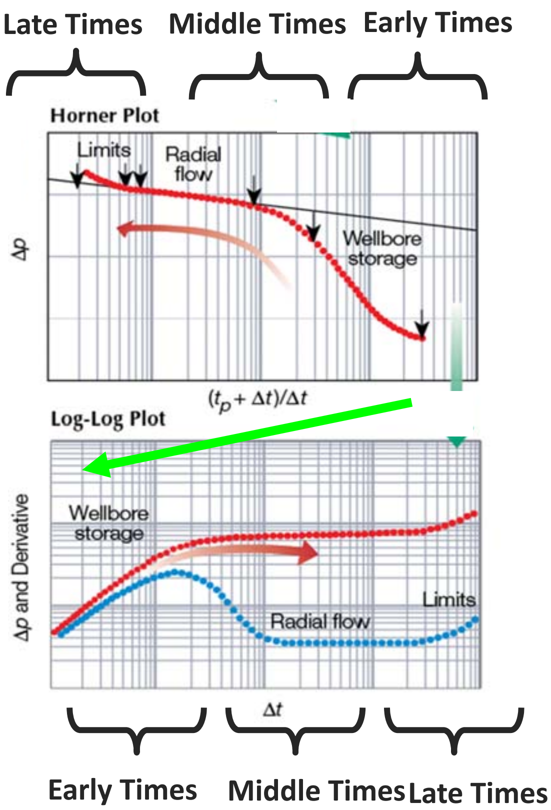
Variation of well rate (at the surface) → Well parameters + Reservoir properties → Well P_{wf} measurement versus time(at the bottom)





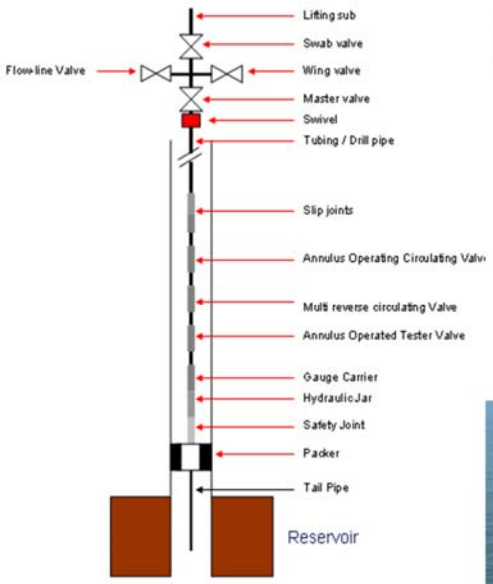
- **Data obtained from a well production test represent the most important source of information about the fluids, the flow geometry, and the dynamic properties of the reservoir rock (k_{eff}) a well as reservoir pressure.**

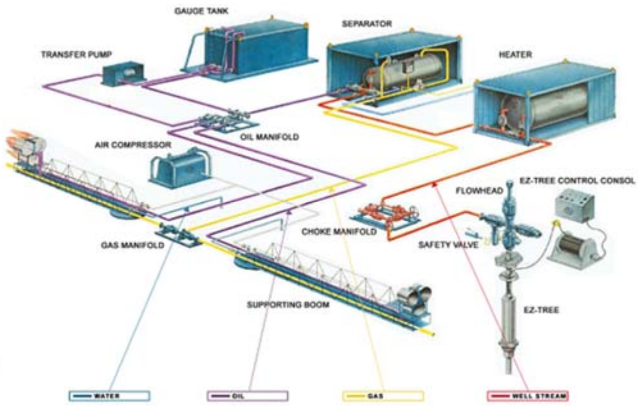
How ?



- **Conventional methods**
- **Derivative**
- **Type curves**
- **Log-log computer assisted**

Now what ?

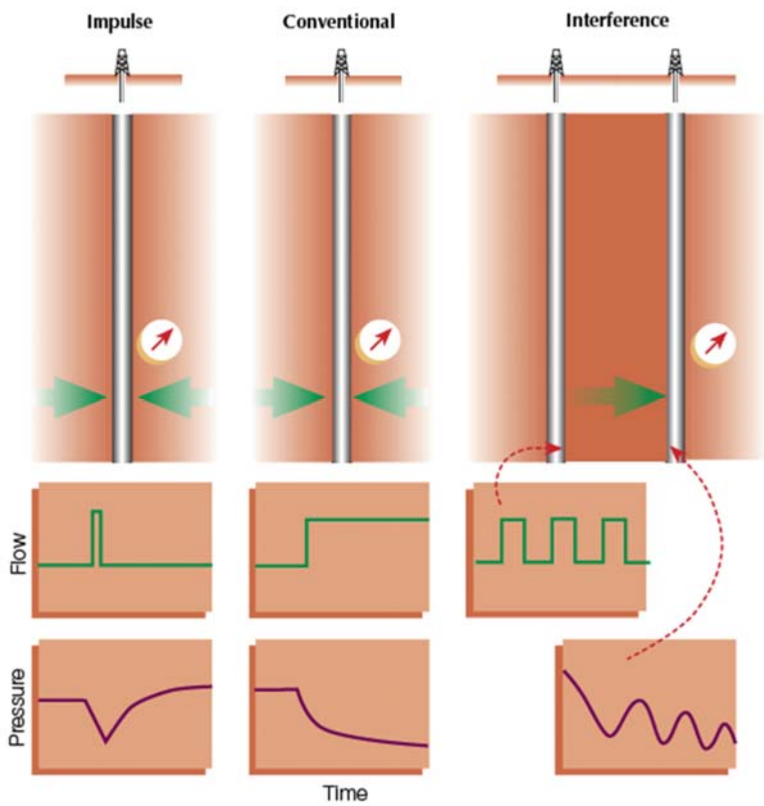




Down hole equipment
Surface equipment

Well testing & Analysis

Different types of tests



- **Impulse test:**
  - **investigation of near wellbore region**
- **Conventional test:**
  - can be of long duration and can detect reservoir limits
- **Interference test:**
  - Measures the transient response in an observation well caused by impulse(s) in an active well
  - May be of very long duration and can detect reservoir limits and assess fault communication

Information obtained from well testing

1. **Reservoir Evaluation (Parameter estimation)**
   - Permeability
   - Skin
   - Drainage area
   - Average pressure & …
2. **Reservoir Description**
   - Detection of heterogeneities
   - Fault
   - When reservoir properties vary with r
   - Naturally fractured reservoirs
   - Pressure drop in the reservoir
3. **Well description**
   - Production potential (productivity index PI and skin factor S)
   - Well geometry

Different types of tests

- **Well test analysis provides information about the reservoir and about the well in dynamic conditions**
- **The objectives of well testing differ with the stage of the field life:**
  - Exploration well
  - Appraisal well
  - Development well
  - Injection well
  - …

Different types of tests

- **Initial tests**
  - Validation (or not) of the exploration hypotheses
  - Major contribution to the development design and dimensioning
  - Contribution to elaboration of production profiles
  - Estimate of the production potential (PI, Skin, …)
  - Reservoir characterization (k.h, Kv, heterogeneities, limits, …)
  - Initial pressure

- **Periodic tests**
  - Evaluation and justification of specific operations
  - Validation of production forecasts
  - Productivity variations
  - Pressure evolution of the reservoir

Different types of tests

- **Interference test:** one well is produced and pressure is observed in a different well (observation well)

- **Pulse test:** the active well is produced with series of short flow / shut-in periods and the resulting pressure oscillations in the observation well are analyzed.

- **Drill stem test:** using special tool mounted on the end of the drill string

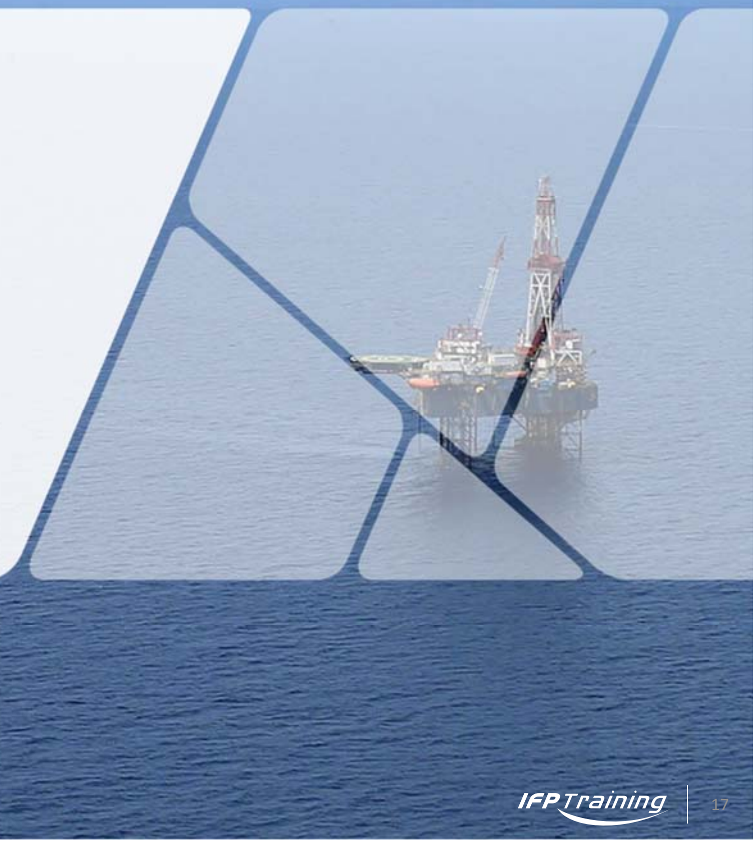
- **Gas well test:** specific testing methods are used to evaluate the deliverability of gas wells (AOFP) and the possibility of non-darcy flow condition (rate dependent skin factor S)

Different types of tests

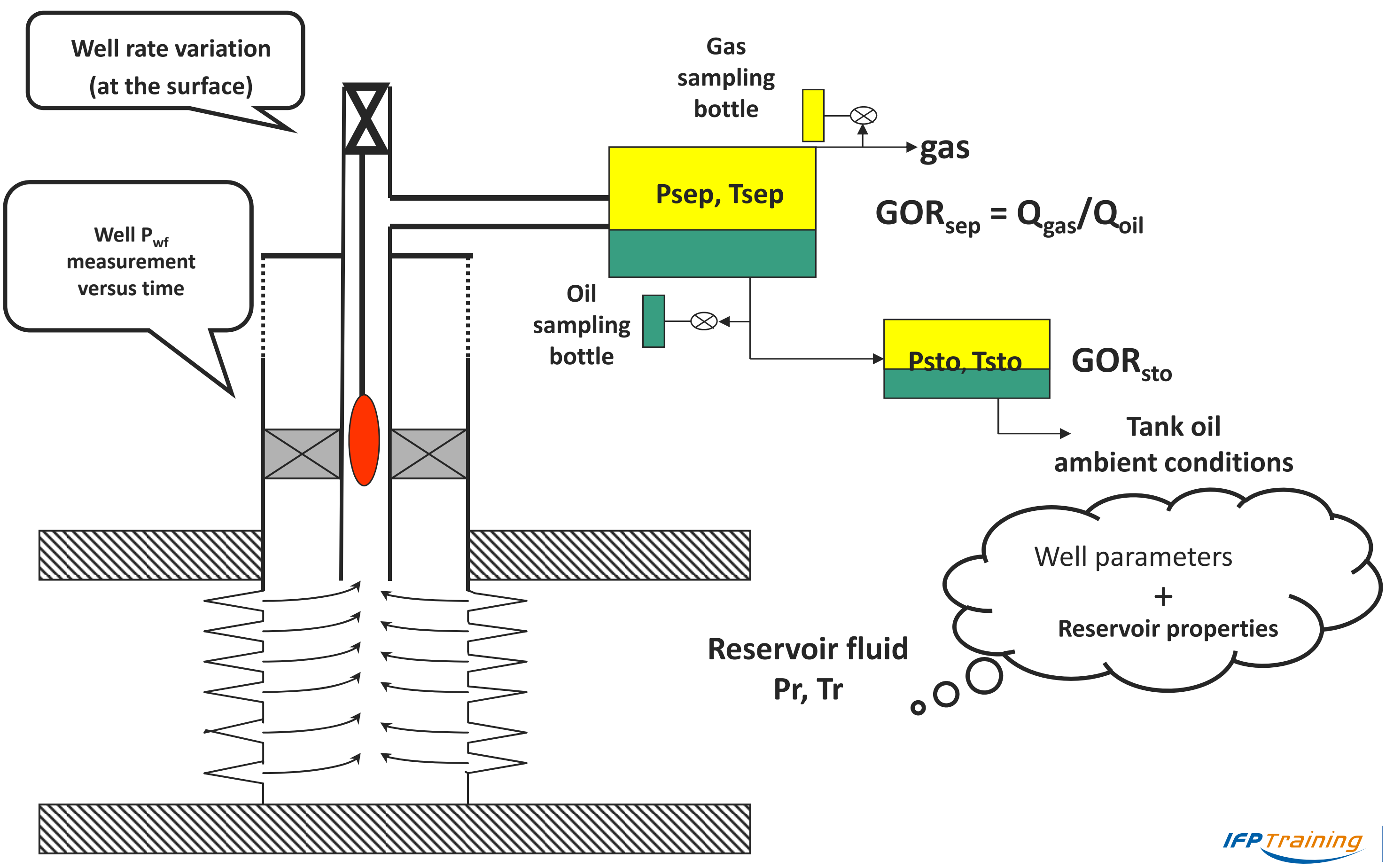
- **Pressure drawdown test**: the well is opened to flow at a constant rate causing pressure drawdown
- **Pressure build-up test**: Production of constant flow rate is shut-in, causing pressure build-up
- **Injection test / fall-off test:** when fluids are injected into the reservoir, the bottom hole pressure increases and, after shut-in, it drops during the fall-off period.
- **Multiple rate test:** well tested at different flow rates, each lasting until the flowing pressure stabilizes. This is followed by a shut-in period, which again lasts until the pressure stabilizes

Notes

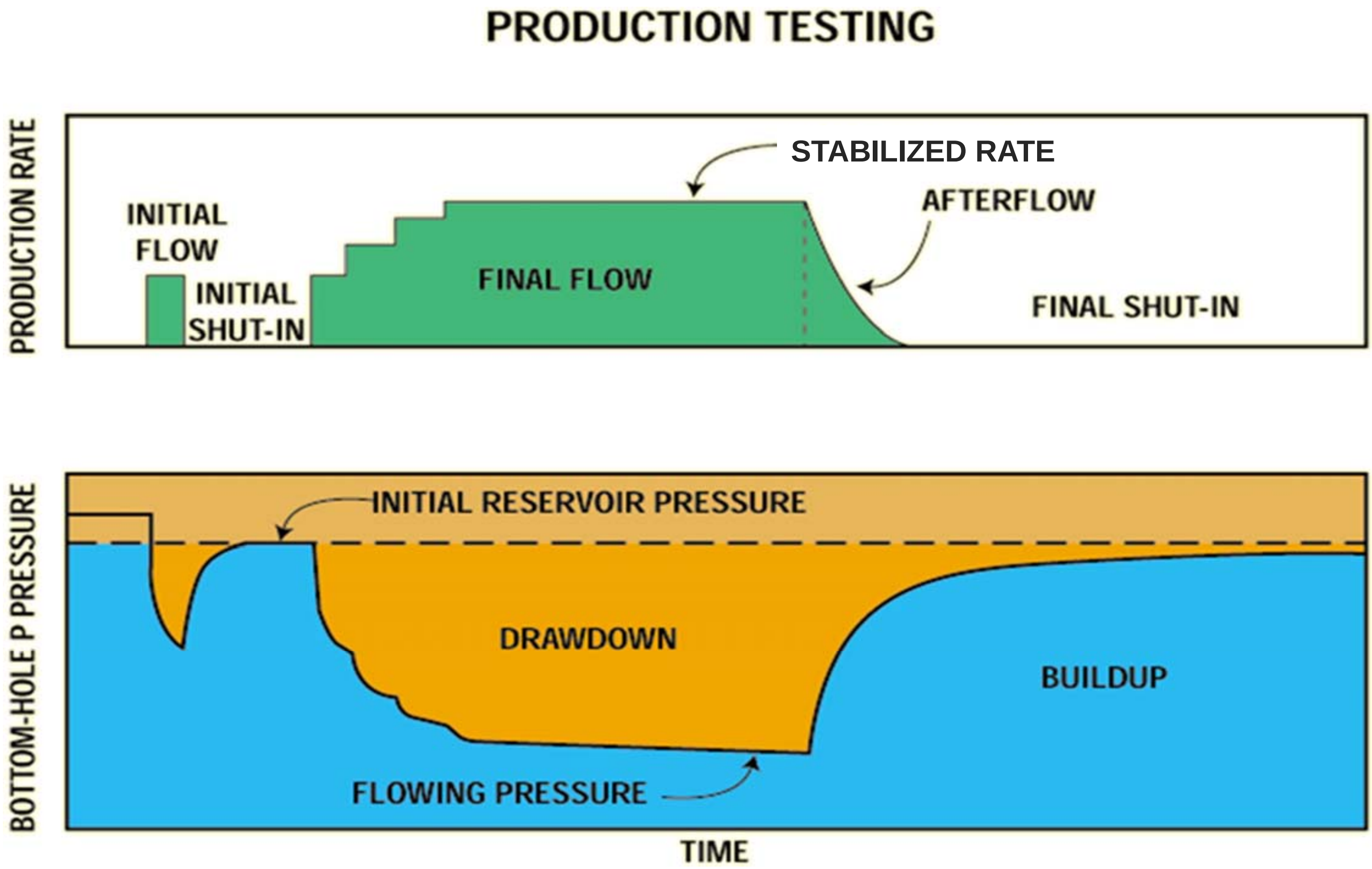
Typical Well Test



Generalities – Typical well test



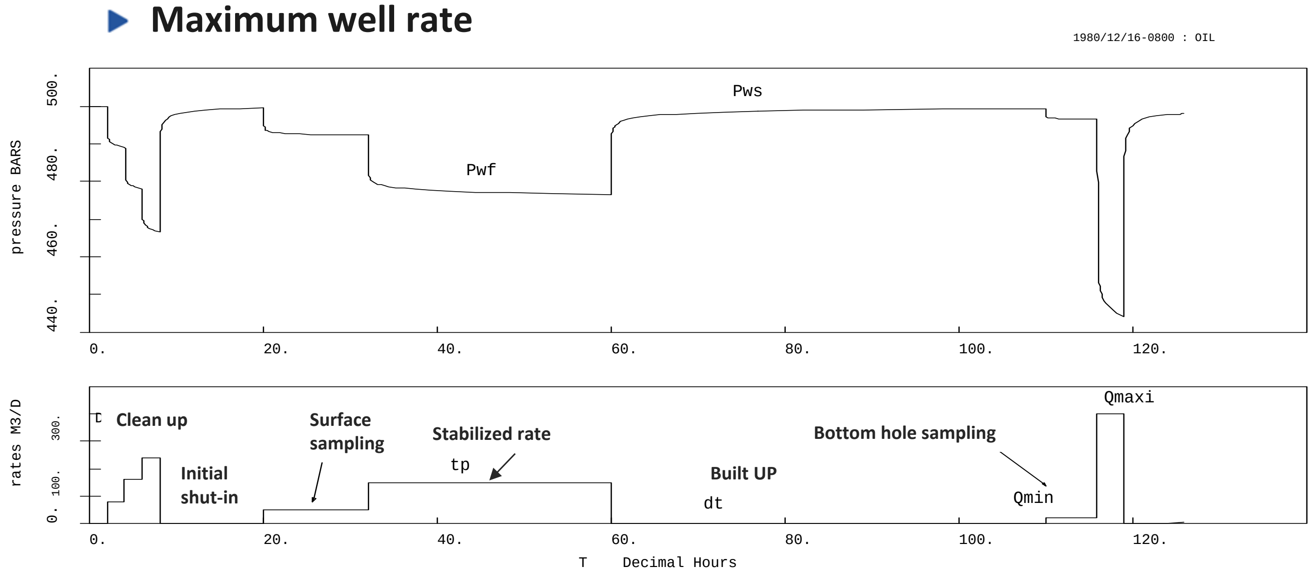
Typical well test



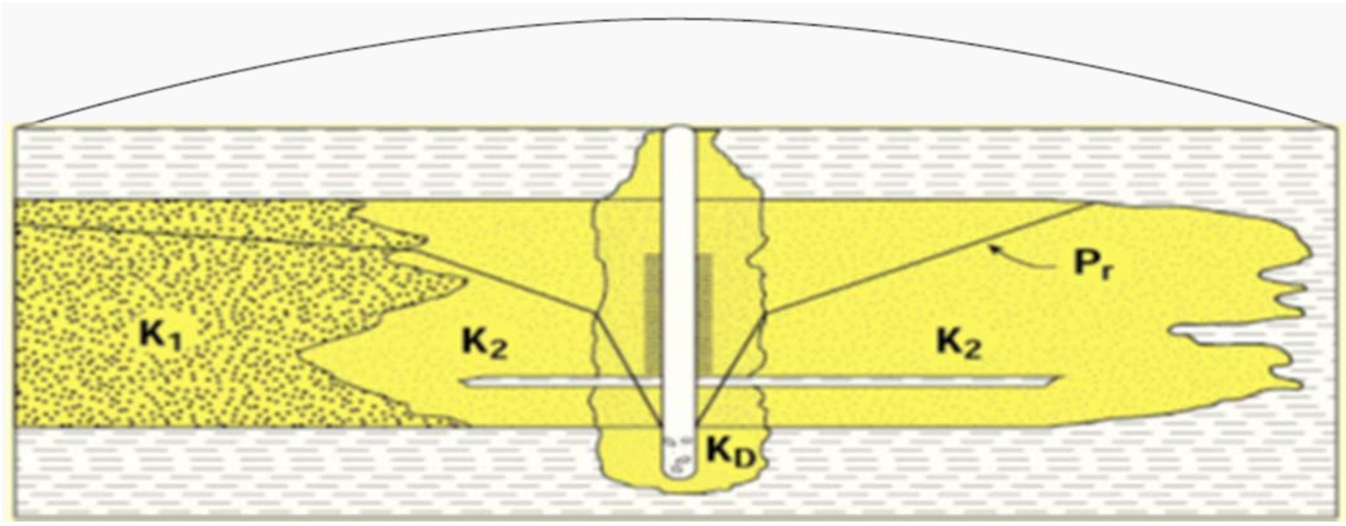
Typical well test

Test sequence example

- Initial Clean-up
- Well RATE and GOR stabilization
- Rate, surface sampling
- Pressure Build-up
- Bottom hole sampling
- Maximum well rate

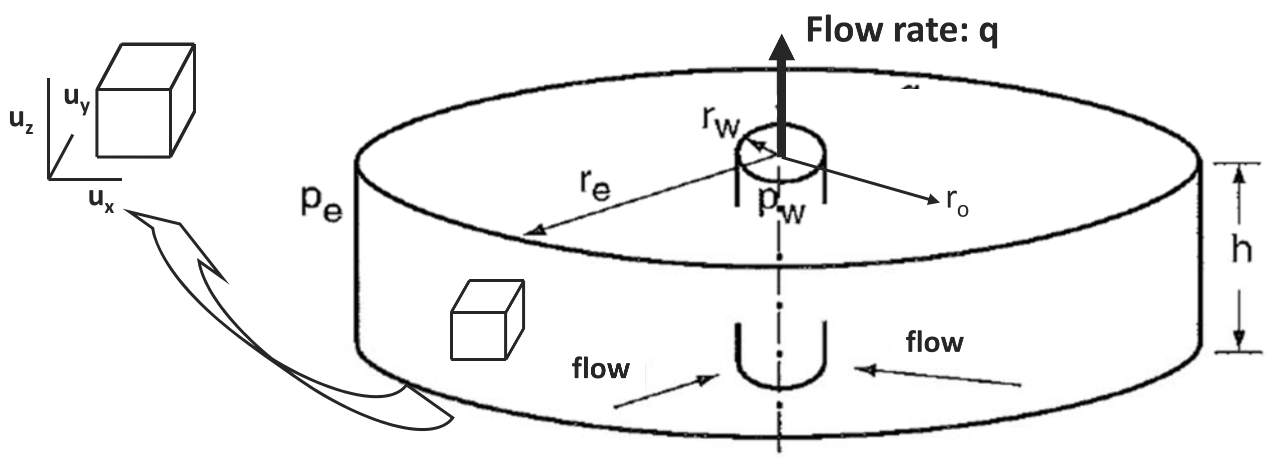


Major reservoir features investigated by a well test



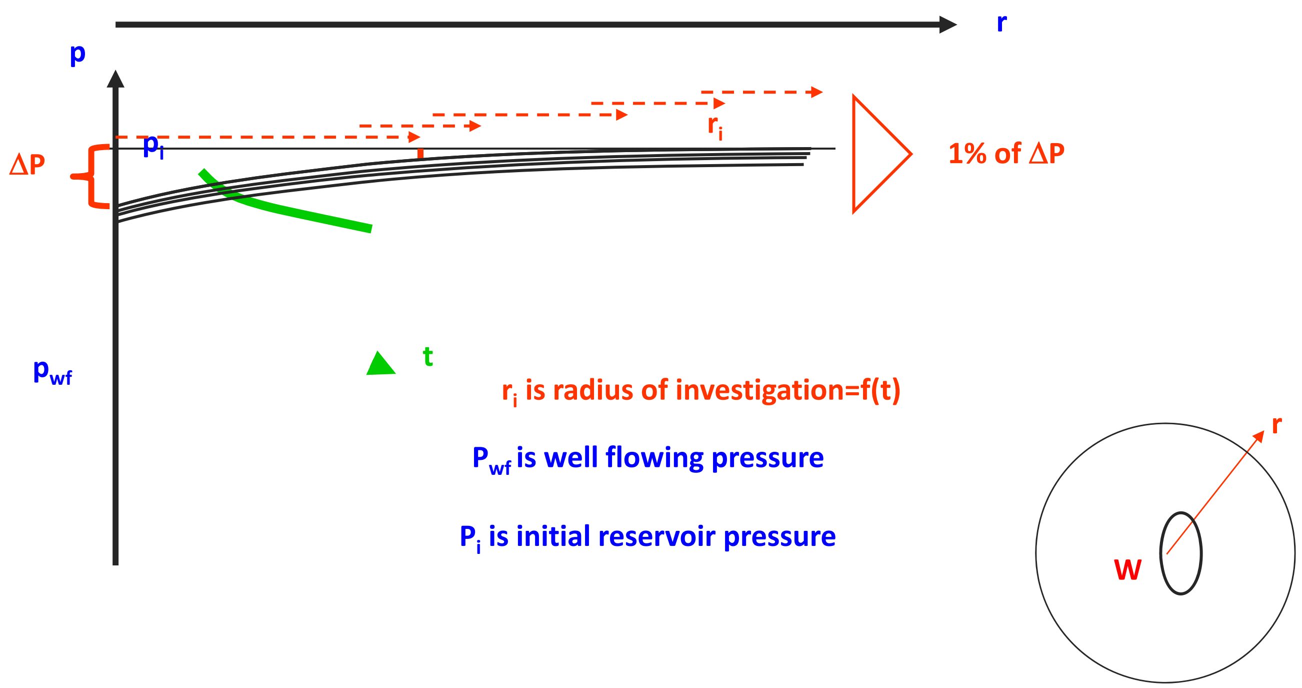
Theoretical Concepts: Principles of WT

- **The basic principle: we produce a well at time t=0, at a given constant flow rate and we observe the induced pressure response.**
- **The pressure can be measured:**
  - At the well bore $P_{(r=rw,\ t)}$: draw down test
  - At a distance from the well bore $P_{(r=ro,t)}$: interference test



Typical well test

- **Schematic example of the pressure response in space and time during drawdown**



r_i is radius of investigation=f(t)

P_{wf} is well flowing pressure

P_i is initial reservoir pressure

Notes

FUNDAMENTALS OF FLUID FLOW IN POROUS MEDIA

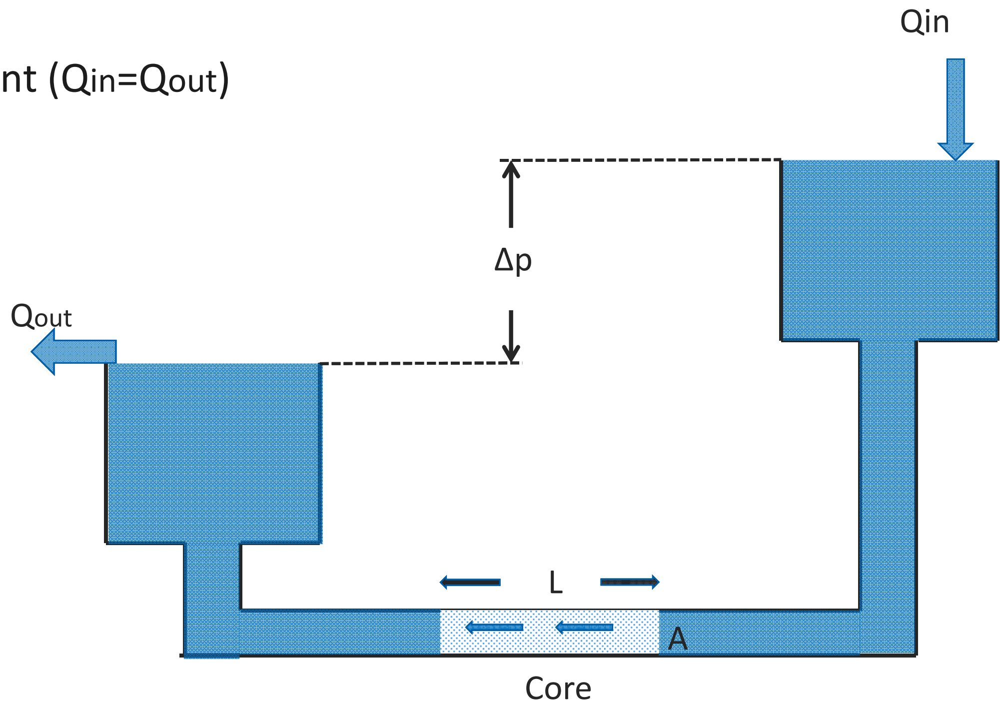
Darcy's experiment

Darcy's experiment was initially set to study the pressure loss due to water flow in sand filters

- Flowrate is kept constant ($Q_{in}=Q_{out}$)

Where

- Q – flowrate
- A – Core length
- K – Permeability
- μ– Fluid Viscosity



Darcy's law

- **Darcy observed that the rate of flow q is:**
  - Proportional to the constant cross - sectional area, A
  - Proportional to the difference in pressure, $(\Delta p = p_2 - p_1)$
  - Inversly proportional to the length, L
  - Inversly proportional to the viscosity of the fluid, μ
- **Darcy's equation is written as:**

$$q = k.A.\frac{p_1 - p_2}{L} = -\frac{k}{\mu}.A.\frac{\Delta p}{L} \ in\ Darcy\ unit$$

$$q = -0.001127.\frac{k}{\mu}.A.\frac{\Delta p}{L} \quad in\ field\ units$$

Where **k** is the constant of proportionality, also known as permeability

Darcy's law

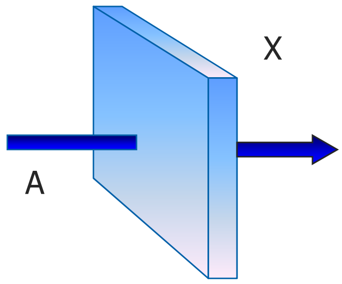
- **Permeability**, k, is a measurement of the fluid conductivity of a porous material
- The quantity k/μ is termed mobility, λ of the fluid.
- **Darcy's Law applies only when the following conditions exist:**
  1. Laminar (viscous) flow
  2. Steady-state flow
  3. Incompressible fluids
  4. Homogeneous formation

Darcy's law in linear and radial coordinates

- **Darcy's law expressed in field units:**

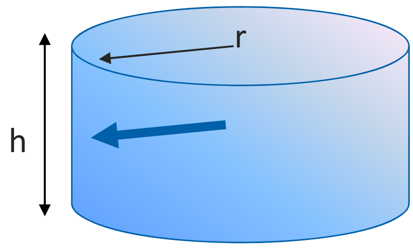
Linear flow

$$\frac{\partial p}{\partial x} = -887.2\,\frac{q\mu}{kA}$$

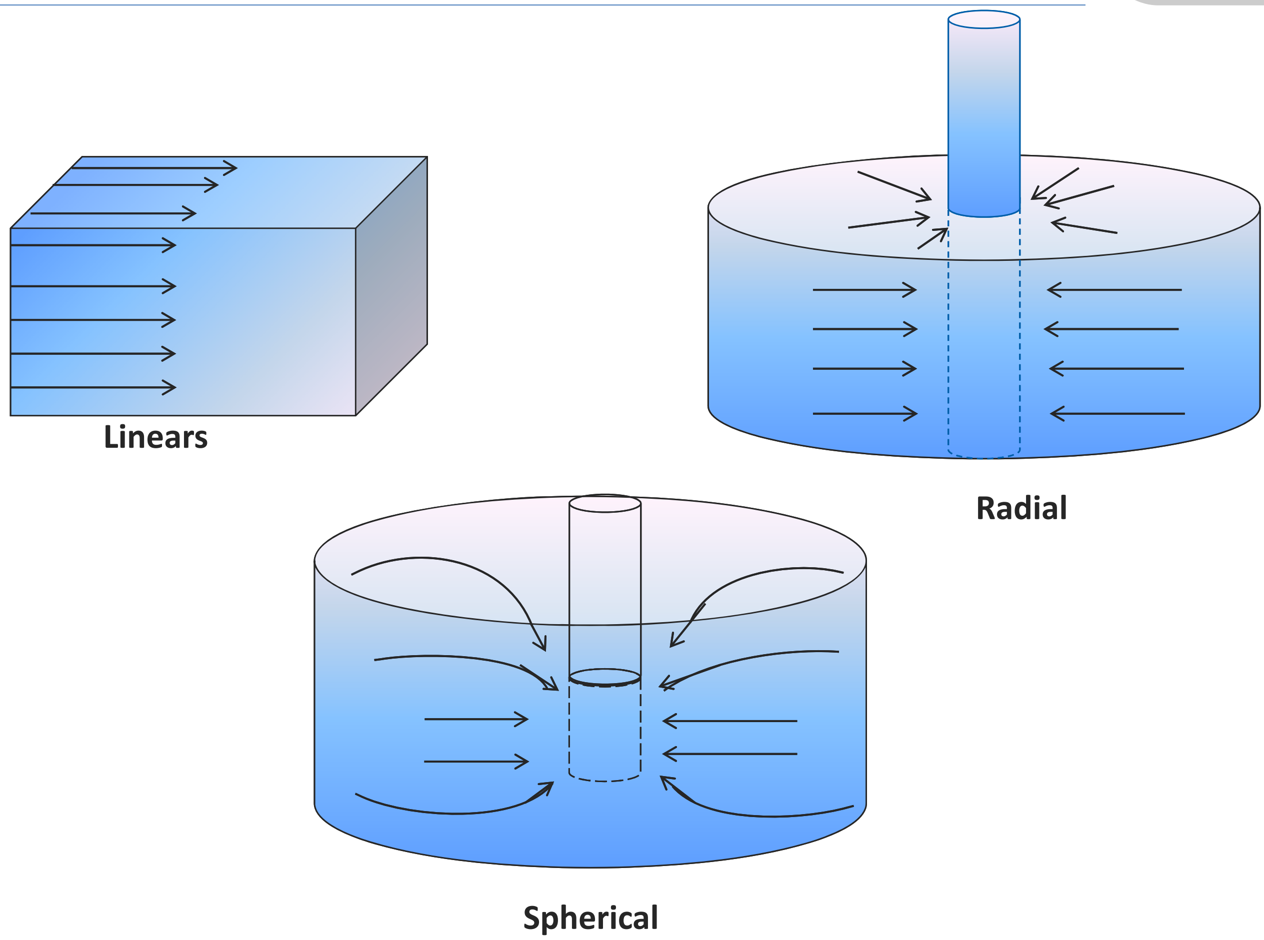


Radial flow

$$r\,\frac{\partial p}{\partial r} = 141.2\,\frac{q\mu}{kh}$$



Flow geometries



Principles – Fluid flow

- **Generally, two kinds of situations can occur in a reservoir:**
  - Flow of only one fluid, either alone in the layer or in the presence of another immobile fluid (**single-phase flow**)
  - Two or three fluids move simultaneous (**multiphase flow**)
- **The laws of one-phase fluid mechanics:**
  - Are relatively simple,
  - Relate the flow rates and pressures in space, as a function of time, as well as of a number of rock and fluid properties.

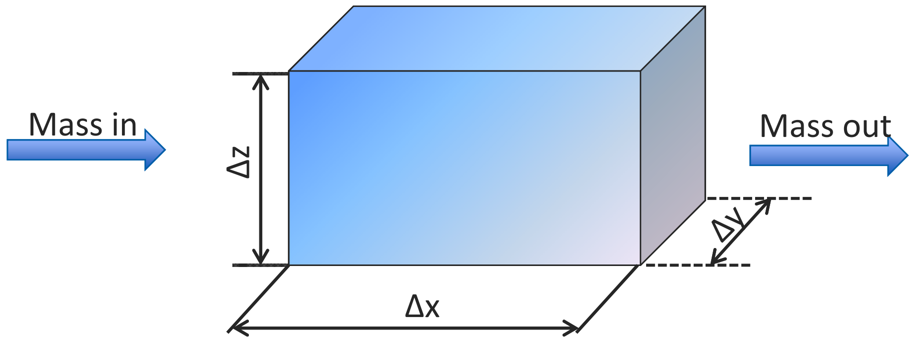
Typically, well tests are conducted to obtain information about a well or a reservoir

Diffusivity equation

- **The basic theory in Dynamic Data Analysis (Well Test Analysis) uses the simplest possible diffusivity equation, assuming the following:**
  - The reservoir is homogeneous and isotropic
  - The fluid is single-phase and only slightly compressible
  - Gravity effects are ignored
  - Darcy's law applies
  - Constant reservoir temperature
  - Reservoir and fluid properties are independent of the pressure
- **Diffusivity equation is derived from the combination of**
  - The continuity equation or the principles of conservation of mass
  - Transport equation (Darcy's law)
  - Equation of state

Continuity equation

- Considering an element of the reservoir through which a single phase is flowing in the x direction at, any time:



Conservation of mass: $\boldsymbol{Mass\ rate}_{\ in} - \boldsymbol{Mass\ rate}_{\ out} = \boldsymbol{Mass\ rate\ of\ accumulation}$

$$(\rho_x v_x \Delta y \Delta z) - \rho_{x+\Delta x} v_{x+\Delta x} \Delta y \Delta z = (\Delta x \Delta y \Delta z)\,\frac{(\phi\rho)_{t+\Delta t} - (\phi\rho)_t}{\Delta t}$$

Dividing both sides by $\Delta x \Delta y \Delta z$:

$$-\frac{(\rho_{x+\Delta x} v_{x+\Delta x}) - (\rho_x v_x)}{\Delta x} = \frac{(\phi\rho)_{t+\Delta t} - (\phi\rho)_t}{\Delta t}$$

When Δx and Δt tend to zero simultaneously then:

$$\frac{\boldsymbol{\delta(\rho v)}}{\boldsymbol{\delta x}} = -\frac{\boldsymbol{\delta(\phi\rho)}}{\boldsymbol{\delta t}}$$

Continuity equation (cont.)

- The continuity equation for the three dimensions:

$$\frac{\boldsymbol{\delta(\rho v)}}{\boldsymbol{\delta x}} + \frac{\boldsymbol{\delta(\rho v)}}{\boldsymbol{\delta y}} + \frac{\boldsymbol{\delta(\rho v)}}{\boldsymbol{\delta z}} = -\boldsymbol{\phi}\frac{\boldsymbol{\delta\rho}}{\boldsymbol{\delta t}}$$

- The continuity equation for radial flow

$$\frac{\mathbf{1}}{\boldsymbol{r}}\frac{\boldsymbol{\delta}}{\boldsymbol{\delta r}}(\boldsymbol{r\rho v}) = \boldsymbol{\phi}\frac{\boldsymbol{\delta\rho}}{\boldsymbol{\delta t}}$$

N/B: $\boldsymbol{v}$ - is the velocity of the fluid

Equation of state

An equation of state is needed to express the density in terms of pressure

- Compressibility is defined as:

$$c = -\frac{1}{V}\left(\frac{\delta V}{\delta p}\right)_T$$

- Most oil field liquid systems are considered as slightly compressible:

$$c_f = \frac{1}{\rho}\left(\frac{\delta \rho}{\delta p}\right)$$

$$\rho = \rho_o[1 + c_o(p - p_o)]$$

- For compressible fluids:

$$PV = znRT \rightarrow \ \rho = \frac{M_w}{RT}\frac{p}{z}$$

- Pore compressibility:

$$c_p = \frac{1}{\phi}\left(\frac{\delta \phi}{\delta p}\right)$$

Diffusivity equation

- The combination of the Darcy's law, the continuity equation and the equation of state (EOS) leads to the Diffusivity equation
- For a slightly compressible fluid, flowing in the x direction
  - Darcy's law: $v = \frac{q}{A} = -\frac{k}{\mu}\frac{\delta p}{\delta x}$
  - Continuity equation: $\frac{\delta(\rho v)}{\delta x} = -\frac{\delta(\phi \rho)}{\delta t}$

$$\frac{\delta}{\delta x}\left(-\frac{k\rho}{\mu}\frac{\delta p}{\delta x}\right) = -\frac{\delta(\phi\rho)}{\delta t}$$

Expanding yields: $-\left[\frac{k}{\mu}\frac{\delta^2 p}{\delta x^2}\rho + \frac{k}{\mu}\frac{\delta \rho}{\delta P}\left(\frac{\delta p}{\delta x}\right)^2\right] = -\rho\phi\left[\frac{1}{\rho}\frac{\delta\rho}{\delta p} + \frac{1}{\phi}\frac{\delta\phi}{\delta p}\right]\frac{\delta p}{\delta t}$

Diffusivity equation

- **Compressibility equations**: $c_f = \frac{1}{\rho}\left(\frac{\delta \rho}{\delta p}\right)$ & $c_p = \frac{1}{\phi}\left(\frac{\delta \phi}{\delta p}\right)$
- Diffusivity equation:

$$\frac{\delta^2 p}{\delta x^2} = \frac{\phi \mu c_t}{k}\frac{\delta p}{\delta t}$$

- **In radial coordinates, the diffusivity equation**

$$\frac{1}{r}\frac{\delta}{\delta r}\left(r\frac{\delta p}{\delta r}\right) = \frac{\phi \mu c_t}{k}\frac{\delta p}{\delta t}$$

$\eta = \frac{k}{\phi \mu c_t}$ is the **hydraulic diffusivity**

Diffusivity equation

- **General form of the diffusivity equation:**

$$\boldsymbol{\nabla^2 p = \frac{\phi \mu c_t}{k}\frac{\delta p}{\delta t}}$$

- **Assumptions**
  - Homogeneous isotropic reservoir
  - Uniform thickness
  - Constant porosity & permeability
  - Fluid of small & constant compressibility
  - Constant fluid viscosity
  - Small pressure gradient
  - No gravity effect

Symbols & representations
- p= Pressure (psi)
- t = Time (hr)
- k = Reservoir permeability (md)
- Φ = Porosity, dimentionless
- μ = Viscosity (cp)
- C_t = Total compressibility
- r & x = Radial & linear distances

- **Generally, the diffusion equation used in most analytical models is the radial formulation**

Sensitivity of k, ϕ, μ and Ct on η

Hydraulic diffusivity: $\eta = \frac{k}{\phi \mu c_t}$

$$Mobility = \frac{k}{\mu}$$

$$\text{Storativity} = \phi c_t$$

- The larger the permeability, the faster the pressure change
- The larger the viscosity, the slower the pressure change
- The larger the porosity, the lower the pressure change, and therefore slower
- The larger the total compressibility, the lower the pressure change and therefore slower

Initial and boundary conditions

- **The solution of the diffusivity equation depends on the boundary conditions (inner and outer)**
- **Initial condition:**

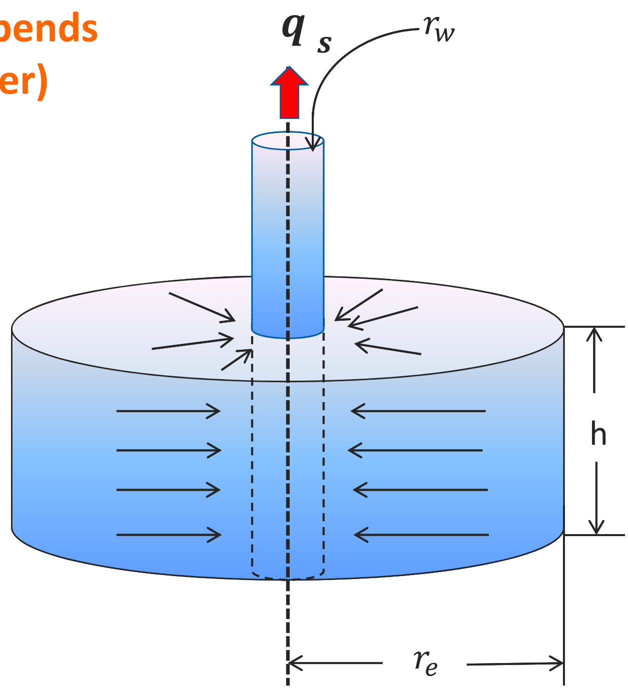
$$p(r, 0-) = p_i\,, \qquad r_w \le r \le r_e$$

- **Inner boundary condition**

$$\left[r\frac{\partial p}{\partial r}\right]_{r_w,t} = 141.2\frac{q_s B\mu}{kh}$$

Line source approximation:

$$\left[r\frac{\partial p}{\partial r}\right]_{r\to 0,t} = 141.2\frac{q_s B\mu}{kh}$$

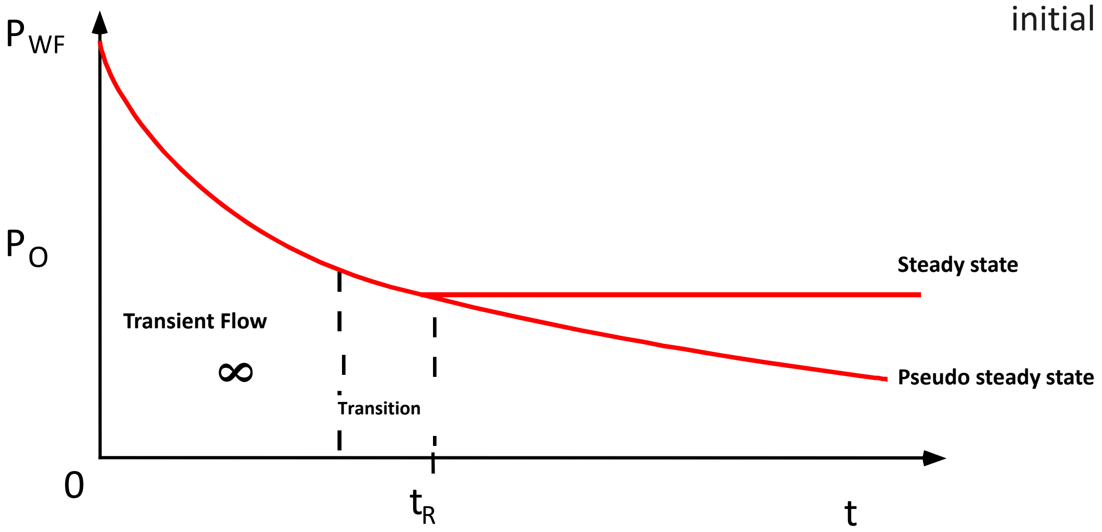


Flow regimes: radial flow

Solutions of the diffusivity equation

- **Many solutions depend on boundary conditions:**
  - space: at well and outer boundary
  - time: initial rate

initial pressure



External boundary conditions

Flow regimes

- **Infinite reservoir case:** $p(r,t) = p_i \; as \; r \to \infty$

  → Transient (Unsteady) state: $\frac{\partial p}{\partial t} = f(x,y,z,t)$

- **Bounded reservoir case:** $\left.\frac{\partial p}{\partial r}\right|_{r=r_e} = 0$

  → Pseudo steady state: $\frac{\partial p}{\partial t} = constant$

- **Constant pressure outer boundary**: $p(r,t) = p_i \;, t > 0$

  → Steady state: $\frac{\partial p}{\partial t} = 0$

Constant rate infinite reservoir case

Line source assumption: Zero radius - No wellbore storage – No skin

- Diffusivity equation:

$$\frac{1}{r}\frac{\delta}{\delta r}\left(r\frac{\delta p}{\delta r}\right) = 3793.5\,\frac{\phi\mu c_t}{k}\frac{\delta p}{\delta t}\ ;\ (In\ field\ unit)$$

- Initial condition:

$$p(r,0) = p_i$$

- Line source (Darcy's equation):

$$\left[r\frac{\partial p}{\partial r}\right]_{r\to 0,t} = 141.2\,\frac{q_s B\mu}{kh}$$

- Boundary condition (infinite reservoir):

$$\lim_{r\to\infty}[p(r,t)] = p_i$$

Constant rate infinite reservoir case

- **The line source solution at any point and time:**

$$p(r,t) = p_i - 70.6\,\frac{qB\mu}{kh}\left[-E_i\left(\frac{948.1\phi\mu c_t r^2}{kt}\right)\right]$$

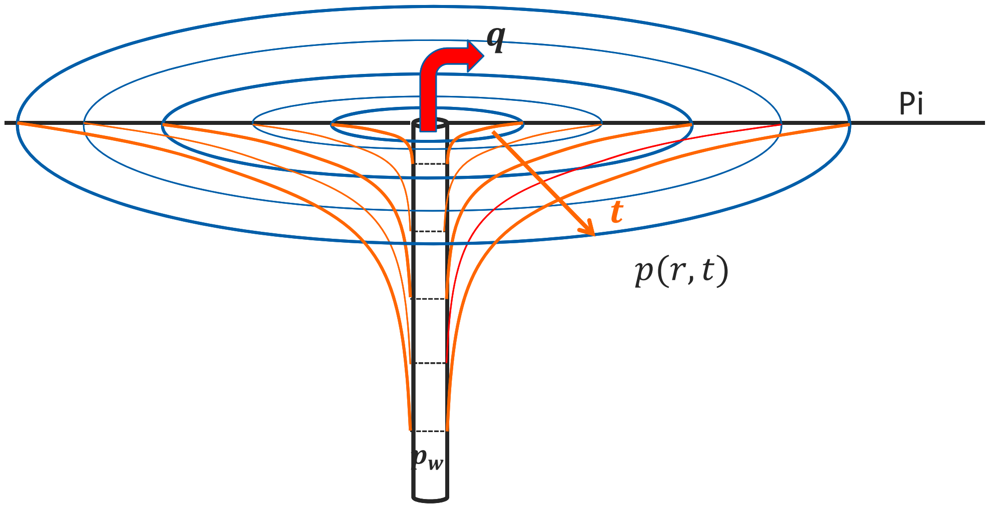
- **Finite well radius**

Infinite Acting Radial Flow (IARF)

When; $t \geq \frac{379200\phi\mu c_t {r_w}^2}{k}$

$$p(t) \approx p_i - 162.6\,\frac{qB\mu}{kh}\left[\log(t) + \log\left(\frac{k}{\phi\mu c_t {r_w}^2}\right) - 3.228\right]$$

Infinite Acting Radial Flow



Transient development of formation pressure distribution

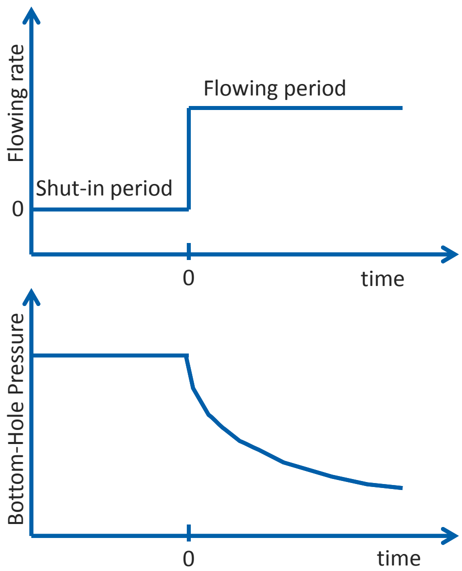
Notes

Notes

PRESSURE DRAWDOWN TESTING

Drawdown test

- Drawdown test is run by producing the well at constant flow rate while continously recording the bottom-hole pressure



Drawdown test

- **The bottom-hole pressure at an active well producing at constant rate in an infinite acting reservoir is given by:**
  - In practical metric units:

$$p_{wf} = p_i - \frac{21.5\ QB\mu}{kh}\left[\log(t) + \log\left(\frac{k}{\phi\mu c_t {r_w}^2}\right) - 3.10 + 0.87S\right]$$

  - In US field units:

$$p_{wf} = p_i - \frac{162.6\ QB\mu}{kh}\left[\log(t) + \log\left(\frac{k}{\phi\mu c_t {r_w}^2}\right) - 3.23 + 0.87S\right]$$

  - This is an equation of a straight line and can be expressed as:

$$p_{wf} = a - m\log(t)$$

Drawdown test

Where

$$a = p_i - \frac{162.6\ QB\mu}{kh}\left[\log\left(\frac{k}{\phi\mu c_t {r_w}^2}\right) - 3.23 + 0.87S\right]$$ In US field units:

- The slope m is given by:

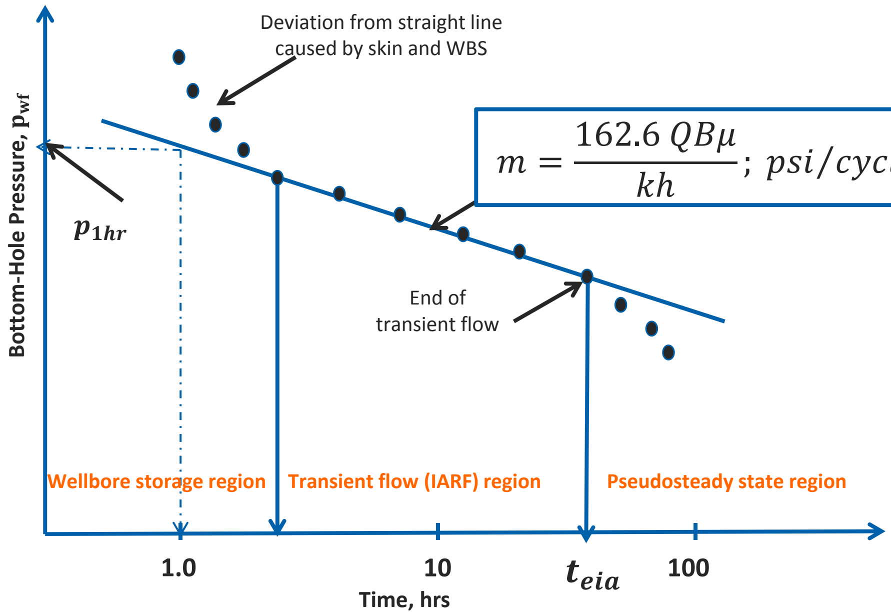
$$m = \frac{162.6\ QB\mu}{kh}$$

The unit of the slope m, is psi/cycle. Notice, slope m is negative

- Then the permeability thickness product can be estimated from the slope of the semi-log plot

$$kh = \frac{162.6\ QB\mu}{m}$$

Drawdown test



Semilog plot of pressure drawdown data

The skin factor can be obtained by:

$$S = 1.151\left(\frac{p_{1hr} - p_i}{m} - \log\frac{k}{\phi\mu c_t {r_w}^2} + 3.23\right)$$

Notes

PRINCIPLE OF SUPERPOSITION

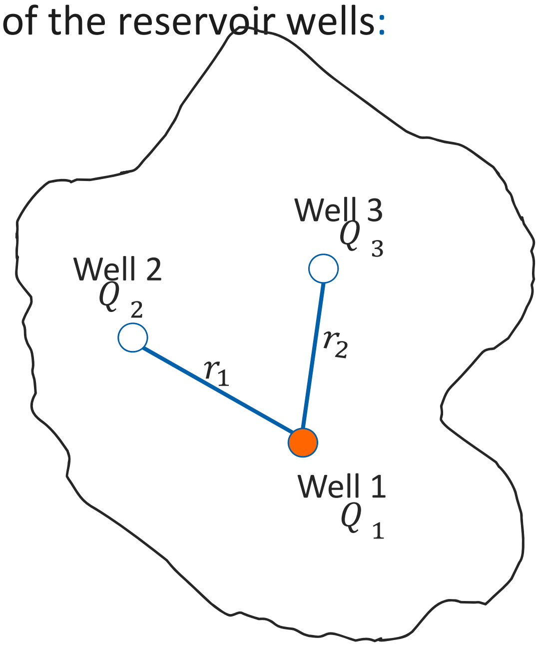
Principle of superposition

- **Mathematically the superposition theorem states that any sum of individual solutions to the diffusivity equation is also a solution to that equation.**
- The superposition principle can be applied to account for the following effects on the transient flow solution:
  - Effect of multiple wells
  - Effect of variable rate
  - Effect of the boundary
  - Effect of pressure change

Principle of superposition

Effect of multiple wells

- Consider the three wells that are producing at different rates from an infinite acting reservoir
- The superposition principle states that the total pressure drop at any point in the reservoir is the sum of the pressure changes at that point caused by flow in each of the reservoir wells:



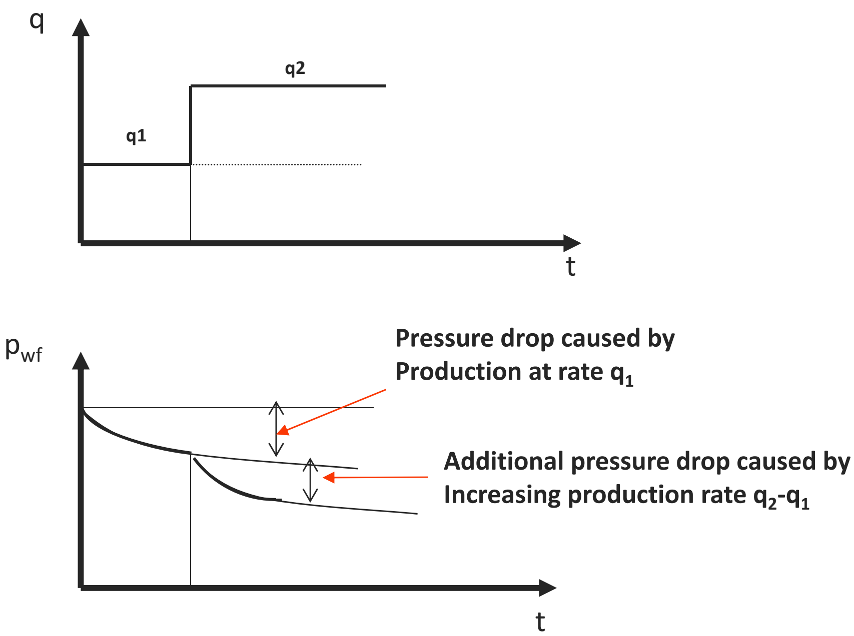
$$
\begin{aligned}
(\Delta p)_{total\ drop\ @\ well\ 1} = {} & (\Delta p)_{drop\ due\ to\ well\ 1} \\
& + (\Delta p)_{drop\ due\ to\ well\ 2} \\
& + (\Delta p)_{drop\ due\ to\ well\ 3}
\end{aligned}
$$

Principle of superposition

Effect of variable rates

Superposition in time:

Every flow rate change in a well will result in a pressure response that is independent of the pressure responses caused by other previous rate changes.



Principle of superposition

Effect of variable rates

- To calculate the pressure at the sandface, the composite solution is obtained by adding individual constant rate solutions at the specific rate-time sequence, or:

$$(\Delta p)_{total} = (\Delta p)_{due\ to\ (Q_{o1}-0)} + (\Delta p)_{due\ to\ (Q_{o2}-Q_{o1})} + (\Delta p)_{due\ to\ (Q_{o3}-Q_{o2})}$$

Where,

$$(\Delta p)_{q_{o1}-0} = \frac{162.6\,(Q_{o1}-0)B_o\mu_o}{kh}\left[log\left(\frac{kt_3}{\phi\mu c_t r_w{}^2}\right) - 3.23 + 0.87S\right]$$

$$(\Delta p)_{q_{o2}-q_{o1}} = \frac{162.6\,(Q_{o2}-Q_{o1})B_o\mu_o}{kh}\left[log\left(\frac{k(t_3-t_1)}{\phi\mu c_t r_w{}^2}\right) - 3.23 + 0.87S\right]$$

$$(\Delta p)_{q_{o3}-q_{o2}} = \frac{162.6\,(Q_{o3}-Q_{o2})B_o\mu_o}{kh}\left[log\left(\frac{k(t_3-t_1)}{\phi\mu c_t r_w{}^2}\right) - 3.23 + 0.87S\right]$$

- This approach can be used to model a well with several rate changes
- N/B: however the approach is valid only if the well is flowing under the transient (unsteady) state condition for the total time elapsed since the well began to flow at its initial rate

Complex rate well test

Superposition time

- To calculate the pressure at the sandface, the composite solution is obtained by adding individual constant rate solutions at the specific rate-time sequence, or:

$$(\Delta p)_{total} = (\Delta p)_{due\ to\ (Q_{o1}-0)} + (\Delta p)_{due\ to\ (Q_{o2}-Q_{o1})} + (\Delta p)_{due\ to\ (Q_{o3}-Q_{o2})}$$

$$\frac{2\pi kh}{\mu}(p_i - p_{w3}) = (q_1 - 0)(p_D(t_{D3} - 0) + S)$$

$$+ (q_2 - q_1)(p_D(t_{D3} - t_{D_1}) + S)$$

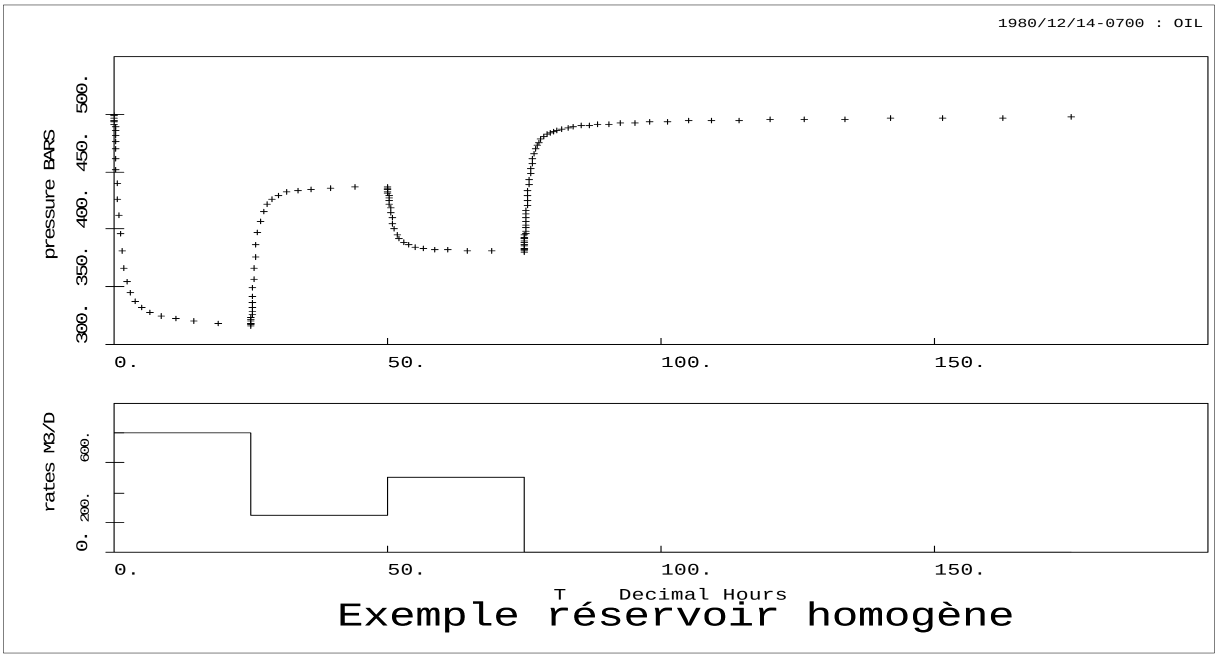
$$+ (q_3 - q_2)(p_D(t_{D3} - t_{D_2}) + S)$$

$$\frac{2\pi kh}{\mu}(p_i - p_{w3}) = \sum_{j=1}^{n} \Delta q_j\, p_D\left(t_{D_n} - t_{D_{j-1}}\right) + q_n S$$

$$\Delta q_j = q_j - q_{j-1}$$

Superposition time; $\sup(\Delta t) = \sum_{i=1}^{n-1} \frac{q_i - q_{i-1}}{q_n - q_{n-1}} \log(t_n - t_i + \Delta t) + \log \Delta t$

Example: variable rate history

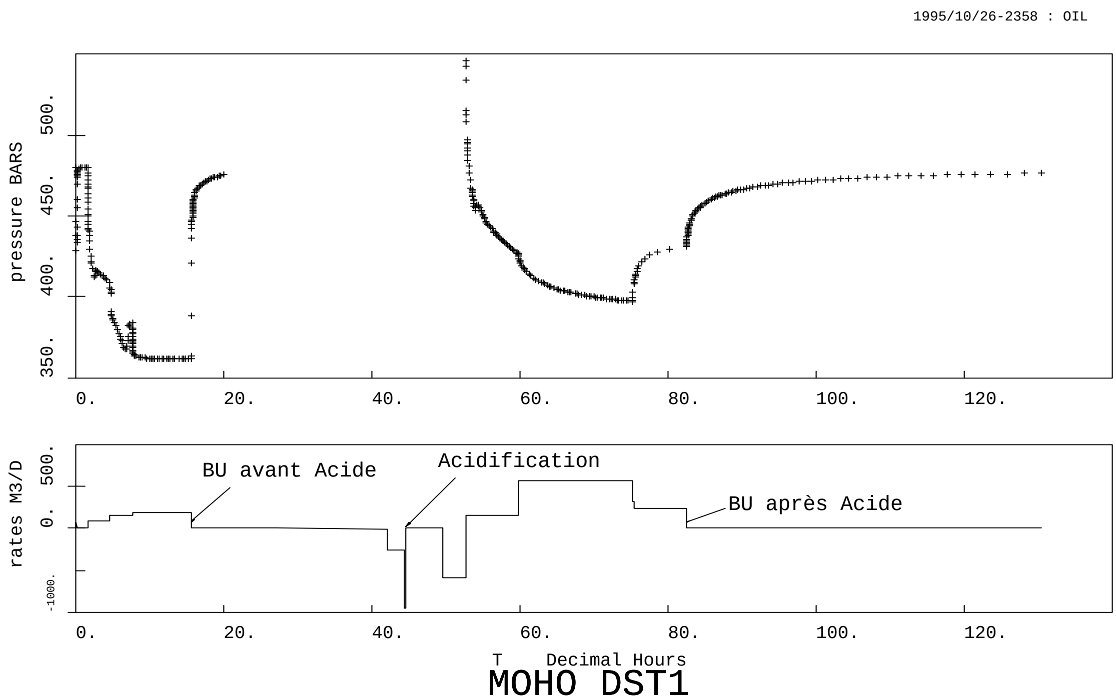


Homogeneous Reservoir
** Simulation Data **
well. storage = .300 M3/BAR
skin = 5.00
permeability = 100. MD
Initial Press. = 500.0 BARS

Static-Data and Constants
Volume-Factor = 1.600 vol/vol
Thickness = 33.00 METRE
Viscosity = 2.000 CP
Total Compress = .9720E-04 1/BAR
Rate = 500.0 M3/D
Storivity = .0004811 METRE/BAR
Diffusivity = N/A METRE^2/HR
Gauge Depth = N/A METRE
Perf. Depth = N/A METRE
Datum Depth = N/A METRE

Example

Complete production history



Notes

CONVENTIONAL Method

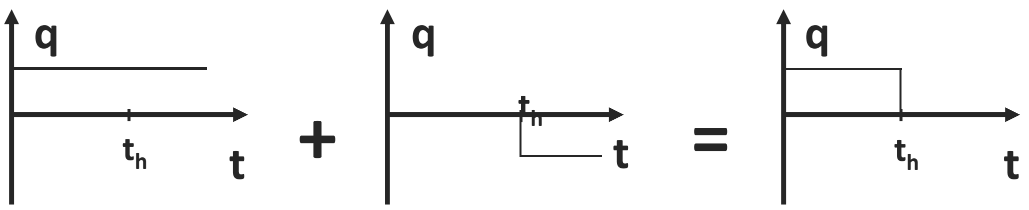
HORNER's Method

INTERPRETATION methods

- A variety of methods exists to interpret well tests; they can be classified into two categories:
  - Conventional methods
  - Methods based on the usage of type curves
- Conventional methods have been developed since the years 1930. They were the only methods available until the 1970's.
- Their interpretation methodology evolved with the advent of type curves; a typical interpretation process:
  - Starts with a diagnosis of the succession of observable flow regimes.
  - Interpretation is done with the objective of quantifying the well – reservoir parameters.
  - Validation of the interpretation model.

HORNER's method

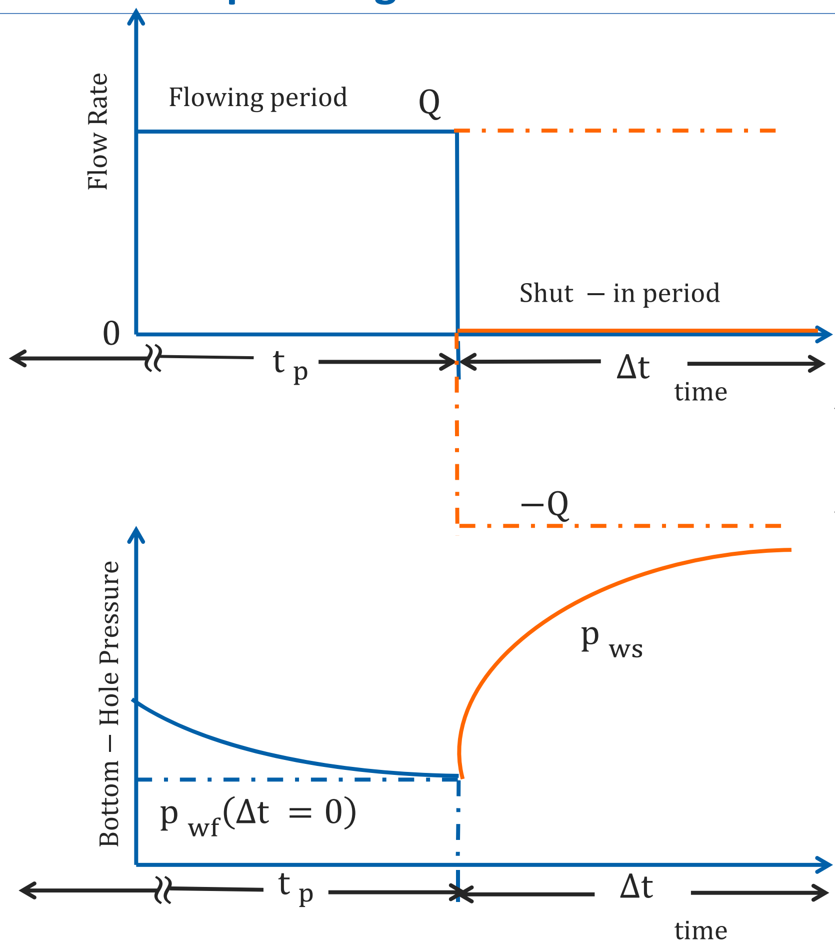
- **The Horner analysis is conducted on pressure build-up data. The production history of the well consists in two phases:**
  - First a pressure draw down phase, corresponding to a constant rate production.
  - Then a pressure build-up phase corresponding to a zero production rate.
- **The superposition principle is then applied to derive the Horner equation.**
- **The major interest of this method resides in the fact that it is much easier to produce a zero rate (Q=0) than a controlled constant rate Q.**



Production starting at time t = 0 | **Injection starting at time $t = t_h$** | **Pressure buildup test**

$$Pi - Pws\,(\Delta t) = \left\{Pi - Pwf\,(th + \Delta t)\right\} - \left\{Pi - Pwf\,(\Delta t)\right\}$$

Pressure build-up testing



t_p – production time

Δt – running shut – in time

p_{ws} – sandface pressure during BU

Derivation of Horner's equation by using the principle of superposition (continued)

- **Principle of superposition:**
  - Independent solutions of linear differential equations can be added to form a new solution.
- **Production starting at time t =0:** $(p_i - p_w)_q = \dfrac{141.2\, q\mu B}{kh}\left[\dfrac{1}{2}\left(\ln\left(\dfrac{\eta t}{r_w^{\,2}}\right) + 0.809\right)\right]$ **(1)**
- **Injection starting at time t = th:** $(p_i - p_w)_{-q} = \dfrac{141.2\,(-q)\mu B}{kh}\left[\dfrac{1}{2}\left(\ln\left(\dfrac{\eta (t - t_h)}{r_w^{\,2}}\right) + 0.809\right)\right]$ **(2)**
- **Add equations (1) and (2) to obtain Horner Equation:**
  [$\Delta t = t - th$; $\ln(x) = 2.303 \log(x)$]

$$p_{ws} = p_i - \frac{162.6\, q\mu B}{kh} \log\left[\frac{t_h + \Delta t}{\Delta t}\right] \qquad (3)$$

Fundamental equation of well test analysis

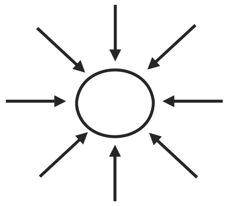
$$P_{ws} = P_i - 162.6\, \frac{Bq\mu}{kh}\left[\log \frac{t_h + \Delta t}{\Delta t}\right]$$

In field units

Pws	=	Shut-in bottom-hole pressure (psi)
Pi	=	Initial reservoir pressure (psi)
q	=	Flow rate (STB/D or KSCF/D)
B	=	Formation volume factor (RB/STB or RB/KSCF)
µ	=	Viscosity (cp)
k	=	Formation permeability (md)
h	=	Formation thickness (ft)
th	=	Horner time (minutes)
Δt	=	Time since shut-in (minutes)
log	=	Common logarithm

Horner's equation assumptions

- Infinite reservoir
- Homogeneous reservoir
- Radial flow
- Constant fluid properties
- Slightly compressible fluid
- Darcy's Law
- Instantaneous shut-in



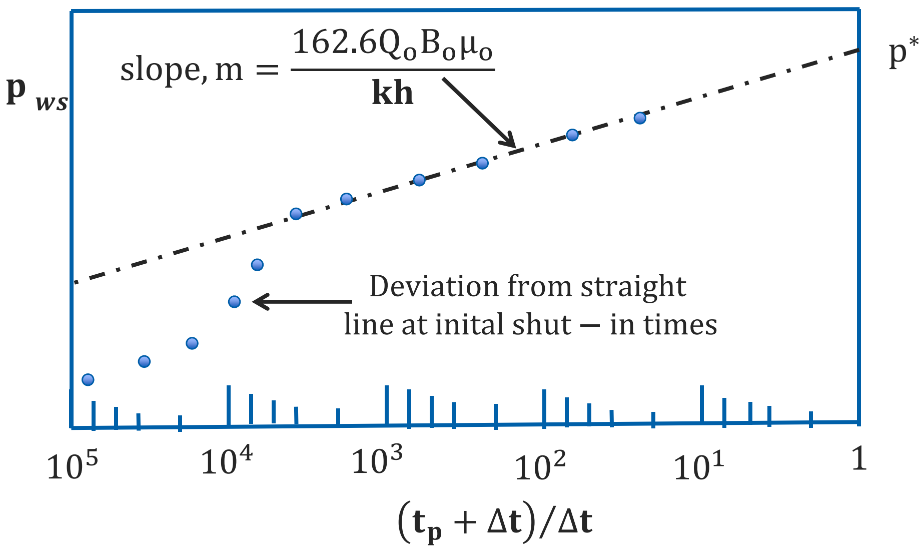
Note: These assumptions sound restrictive, but are usually valid during some portion of <u>most</u> tests.

Horner's plot

- **the equation:**

$$\boxed{p_{ws} = p_i - \frac{162.6\ Q_o\ B_o\ \mu_o}{k\,h}\left[\log\left(\frac{t_p + \Delta t}{\Delta t}\right)\right]}$$

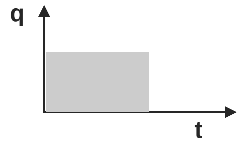
  - Suggests that a plot of p_{ws} vs $\frac{t_p+\Delta t}{\Delta t}$ would produce a straight line relationship with intercept p_i and slope -m



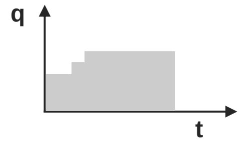
HORNER's equation

Horner Time, t_h

t_h = Producing time, if rate is constant

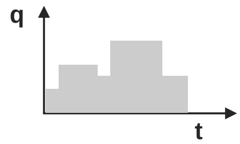


$$t_h = \frac{\text{Cumulative Production}}{\text{Final Flow Rate}}$$, if rate varies slightly



If rate is highly variable, plot:

$$P_{ws} \quad \text{versus} \quad \Sigma \frac{q_i}{q_N} \log \left[\frac{t_N - t_{i-1} + \Delta t}{t_N - t_i + \Delta t} \right]$$



Where:
t_i = time that flow rate q_i ends
t_N = time that well was shut-in

Formation permeability / Average pressure

$$k = \frac{162.6\,Bq\mu}{m\,h}, \text{md}$$

(field units: US)

Pws → p* when Δt → ∞

P* ⟹ INFINITE RESERVOIR Pi = P*; LIMITED RESERVOIR $\overline{P}$

HORNER, SUPERPOSITION

$$k = \frac{C\ Bo\ q\ \mu}{m\ h}$$

C = 0,183	SI units
C = 21,907	Practical metric units
C = 162,59	Oilfield units

HORNER's analysis

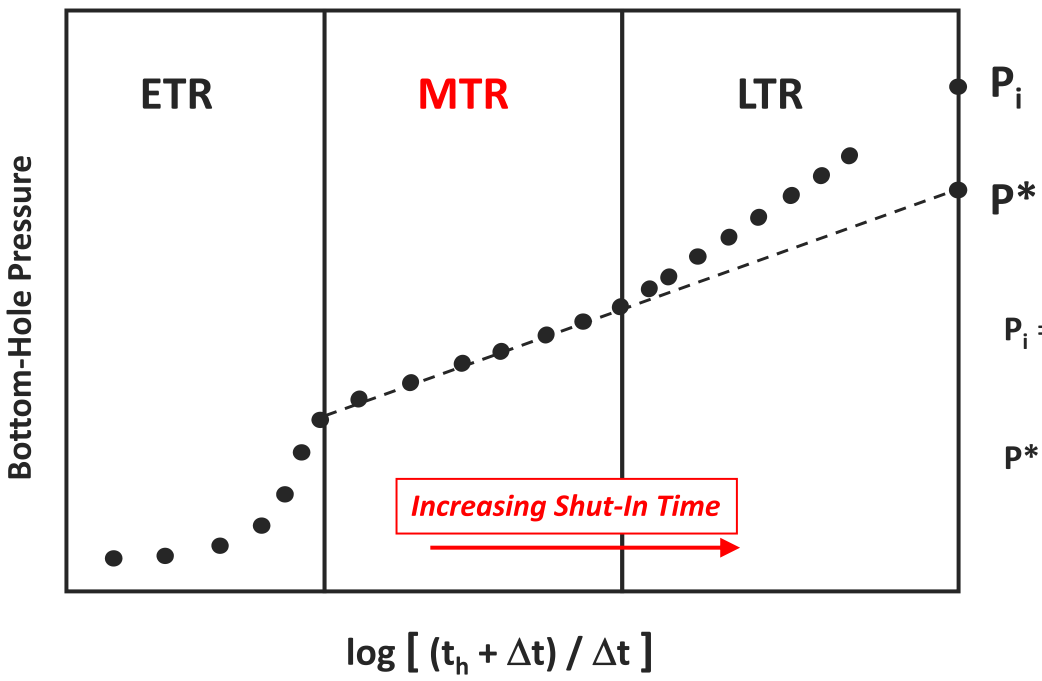
Definition of Regions

- **Middle-Time Region (MTR)**
  - Representative of formation properties
- **Early-Time Region (ETR)**
  - All data **before** MTR
  - Wellbore phenomena (afterflow)
  - Near-wellbore phenomena (damage)
- **Late-Time Region (LTR)**
  - All data **after** MTR
  - Reservoir heterogeneities (boundaries)
  - Change in production / injection rate at nearby well

HORNER's analysis

Horner Plot Regions

However, real data are not so straight …
The straight line, when existing, is restricted to the **M**iddle **T**ime **R**egion



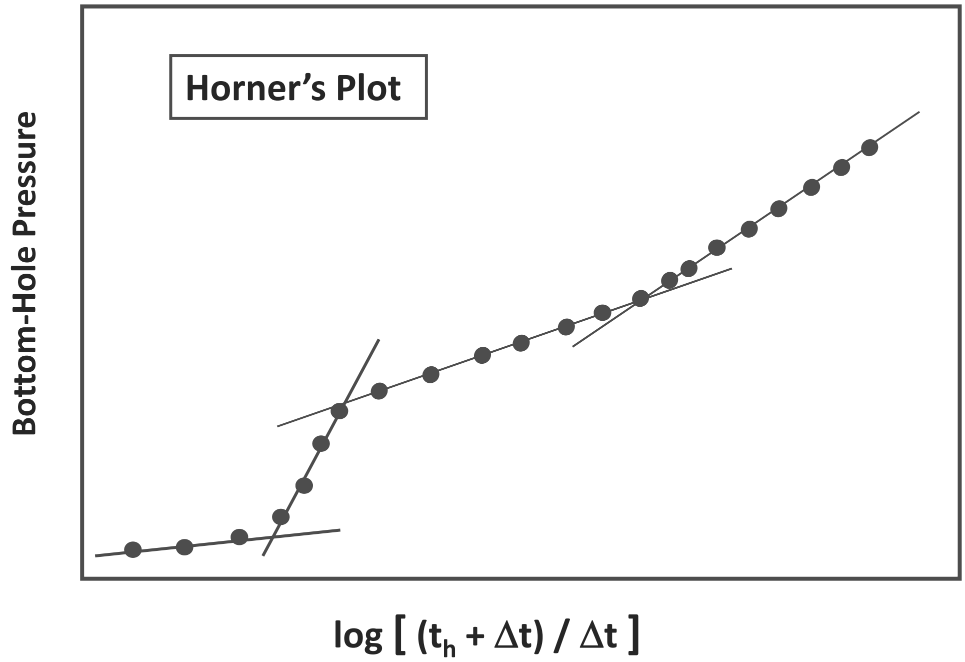
P_i = Initial Reservoir Pressure

P* = Extrapolation of MTR to infinite shut-in time

HORNER's analysis

Which straight-line region is the MTR?

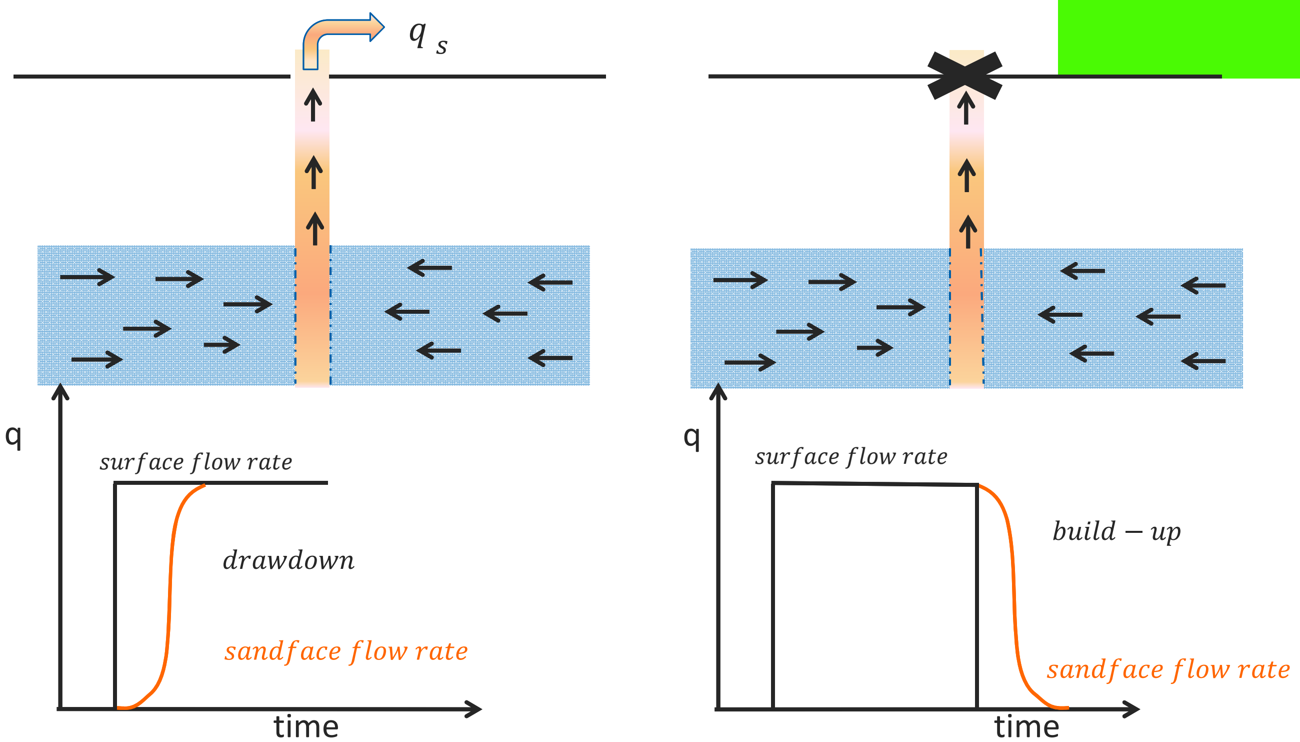
- Which data are representative of the formation properties?



Notes

After Flow
and
Wellbore Storage

Wellbore storage



$$Q_s = Q_f + Q_{wb}$$

Where; Q_s=surface flow rate, bbl/ day

Q_f=formation flow rate, bbl/ day

Q_{wb}= flowrate contributed by the wellbore, bbl/ day

Wellbore storage coefficient

$$\text{Wellbore storage coefficient, } \mathbf{C} = -\frac{\Delta \boldsymbol{V_{wb}}}{\Delta \boldsymbol{p}};\ \left[{}^{bbl}/_{psi}\right]$$

- Considering a drawdown test. When the well is first open to flow after a shut-in period, the pressure in the wellbore drops, causing the following two types of wellbore storage
  - Wellbore storage caused by fluid expansion

$$\mathbf{C} = -\frac{\Delta \boldsymbol{V_{wb}}}{\Delta \boldsymbol{p}} = \boldsymbol{c_{wb} V_{wb}}$$

  - Wellbore storage caused by changing (rise & fall) fluid level in the casing-tubing annulus

$$\mathbf{C} = \mathbf{144}\frac{\boldsymbol{V_u}}{\boldsymbol{\rho g}}$$

Where:

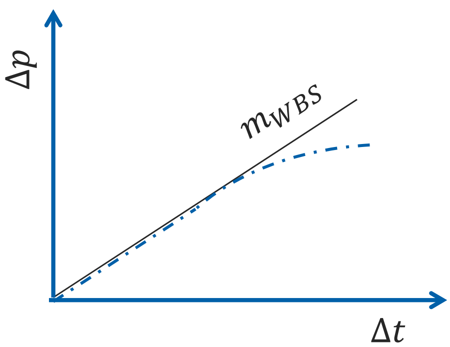
c_{wb}: *fluid compressibility*
V_{wb}: *wellbore volume*
ρ: *liquid density* $({}^{lb}/_{ft^3})$
V_u: *wellbore volume per unit length* (bbl/ft)
g: *gravitational acceleration*

- The relationship between the surface and sandface rate is given by:

$$Q_s B = Q_f B - 24C\frac{\Delta p}{\Delta t}$$

- At early time, the flow is governed by wellbore storage and there is a linear relationship between pressure change and elapsed time

$$\Delta p = \frac{QB}{24C}\Delta t$$



Specialised plot of wellbore storage

$$C = \frac{qB}{24 m_{WBS}}$$

Well bore storage

Well with bottom hole closure	**10^{-4} à 10^{-3} m^3/bar (4 10^{-5} à 4 10^{-4} bbl/psi)**
Well with surface closure	**10^{-2} à 10^{-1} m^3/bar (4 10^{-3} à 4 10^{-2} bbl/psi)**
Pumping well	**0.1 à 1 m^3/bar (4 10^{-2} à 4 10^{-1} bbl/psi)**

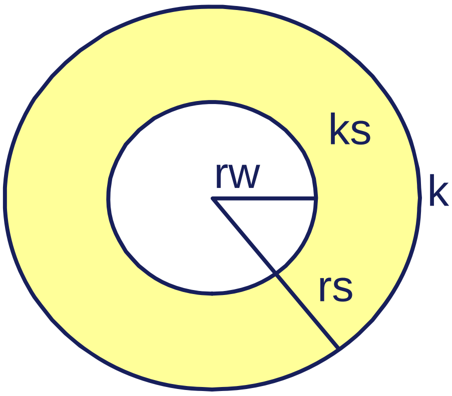
Notes

Skin

Damage
and
Stimulation

Skin

- The properties in the vicinity of the well are different from the reservoir properties, due to drilling, completion or workover operations
- The “skin” is a dimensionless parameter that characterizes the well condition:
  - For a damaged well, S>0
  - For a stimulated well S<0 .
- **The concept of “skin” represents the degree of connection between the reservoir well and the well.**
- **It is translated into an additional pressure drop that can be figured in different ways:**
  - Infinitesimal skin
  - Finite thickness skin
  - Effective radius skin

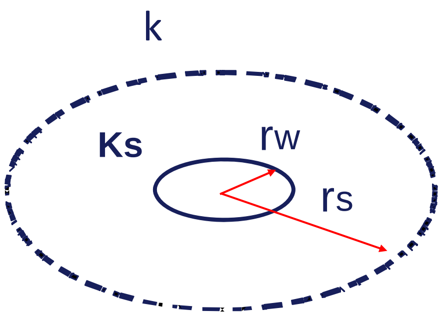


$$\Delta P_{SKIN} = \frac{qB\mu}{2\pi\, kh}\, S$$

$$\Delta P_{SKIN} = \Delta P_{ks}\left(\text{from } \mathbf{rw} \text{ to } \mathbf{rs}\right) - \Delta P_{k}\left(\text{from rw to rs}\right)$$

Expression of the skin:

$$S = \left(\frac{k}{ks} - 1\right) Ln\, \frac{rs}{rw}$$



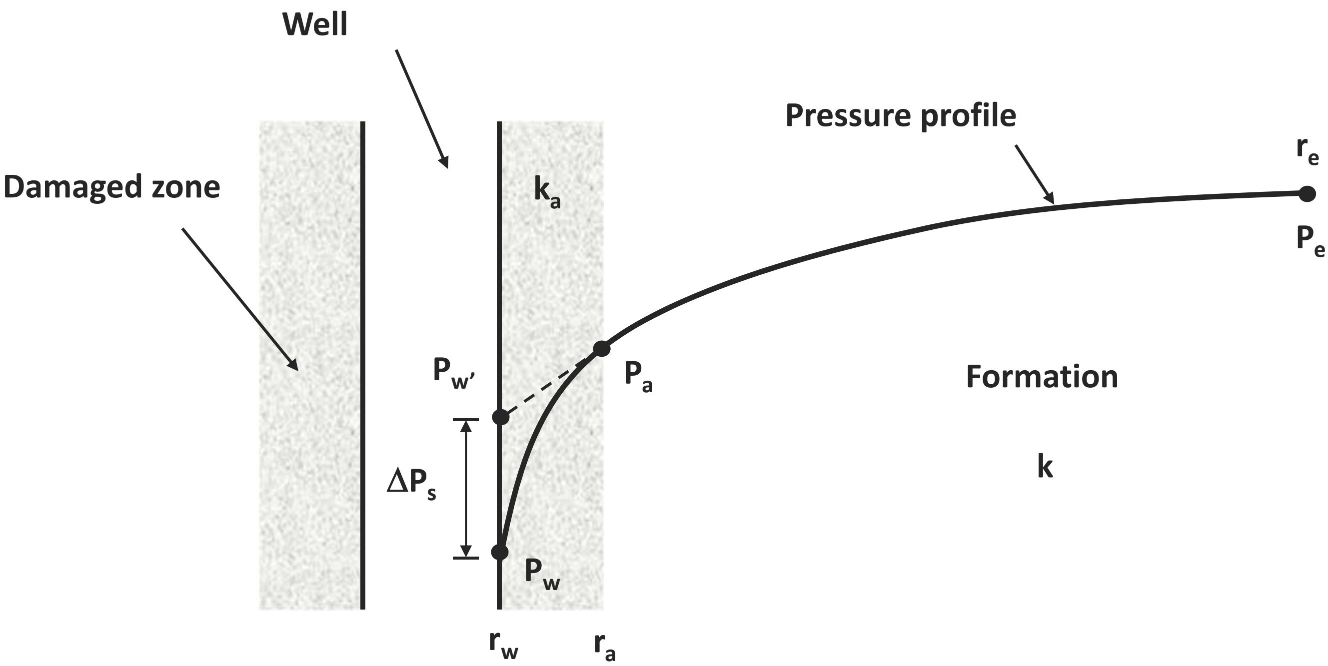
$$S = \left(\frac{k}{ks} - 1\right) Ln\, \frac{rs}{rw}$$

$S>0$ Damaged well

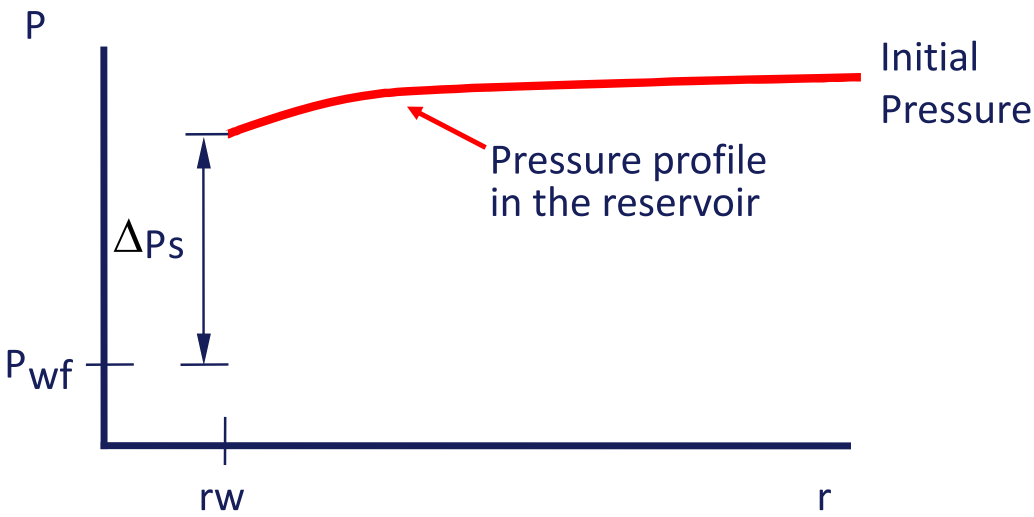
$S<0$ Stimulated well

Damage and skin

- **Well with damaged zone**



Infinitesimal skin



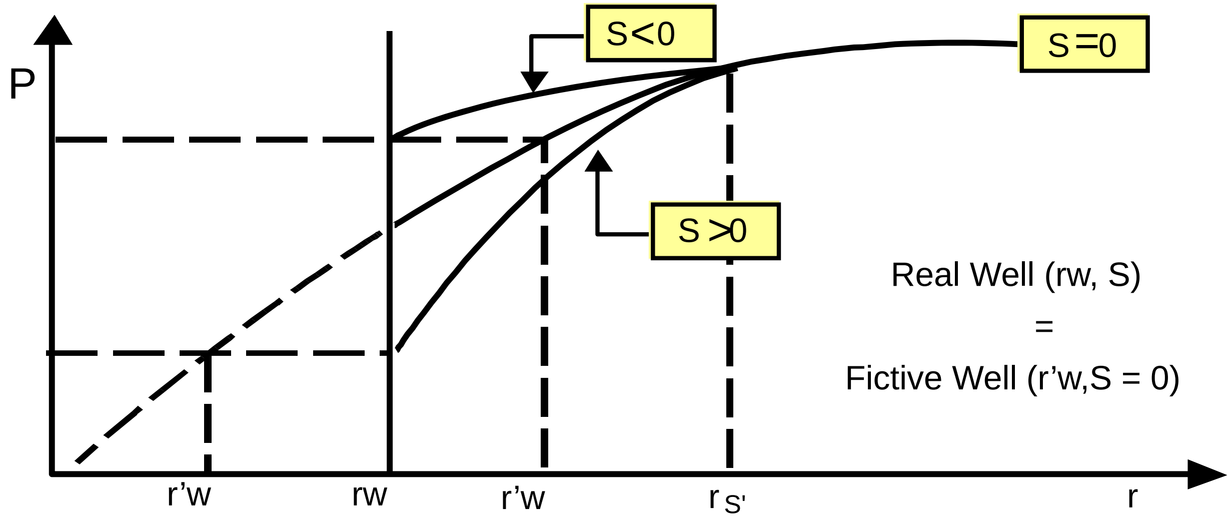
$$DPs = 141.2 \frac{qB\mu}{kh} S$$

Skin

Effective wellbore radius method

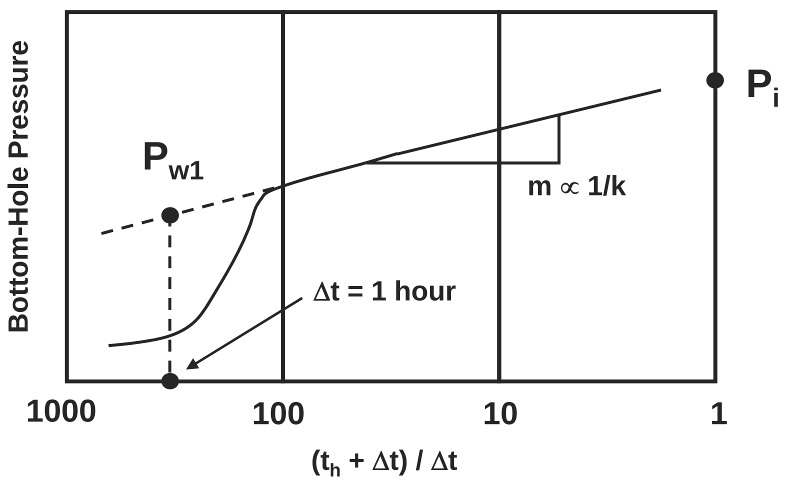
SKIN

EFFECTIVE WELLBORE RADIUS



Skin from the Horner method

$$S = 1.151 \left[\frac{(P_{w1} - P_{wf})}{m} - \text{Log}\left(\frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right]$$



Note:

P_{w1} is either on the MTR line or (as shown) on an extrapolation of the MTR line.

Log = common logarithm

Productivity index

- **The productivity index is defined as the surface fluid production rate per unit pressure drawdown.**

- $$J = \frac{0,053577\,.\,kro\,.\,k\,.\,h}{\mu o\,.\,Bo\,.\left(Ln\left(\frac{re}{rw}\right) - 0,75 + S\right)}$$ in metric units

- $$J = \frac{0,00708\,.\,kro\,.\,k\,.\,h}{\mu o\,.\,Bo\,.\left(Ln\left(\frac{re}{rw}\right) - 0,75 + S\right)}$$ in field units

Notes

Barrier effect on well behavior

Radius of investigation

Barrier effect on well behavior

- The well behavior near a sealing fault or any other barrier to flow was first presented by Horner.
- Horner used the concept of an image well and applied the principle of superposition.

- The production history can be treated as an infinite acting well
- The pressure changes can be added:
  - Pressure change due to the well response in an infinite reservoir

  Plus
  - The interference solution of an image well, symmetric to the well with respect to the fault.
  - Because of the symmetry of the wells positions, a virtual no flow boundary is then created. This no flow boundary simulates the presence of a sealing fault.

No flow boundary – Image well method

FAULT: No flow boundary

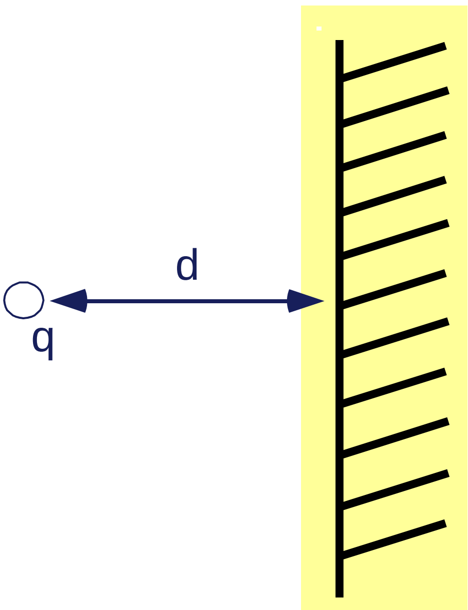
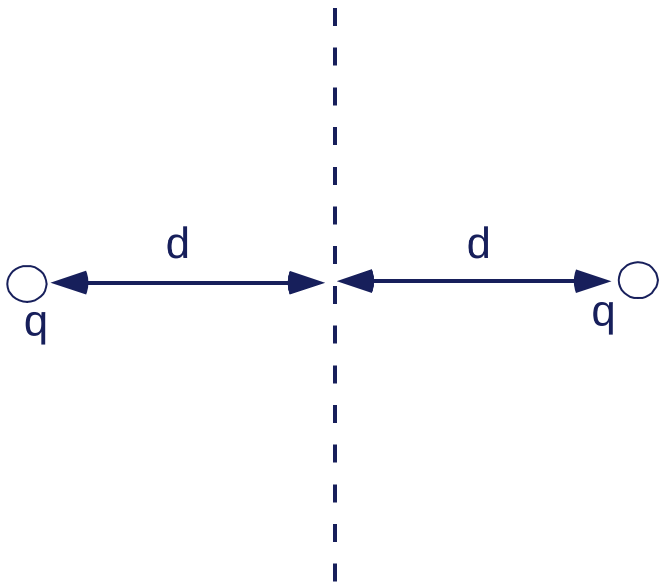


Image well:
symmetric to producing well



- **Superposition with an image well**

$$P_i - P_{wf} = \frac{qB\mu}{4\pi kh}\left(\ln\frac{Kt}{r_w^2} + 0.81 + E_1\left(\frac{+4d^2}{4Kt}\right)\right)$$

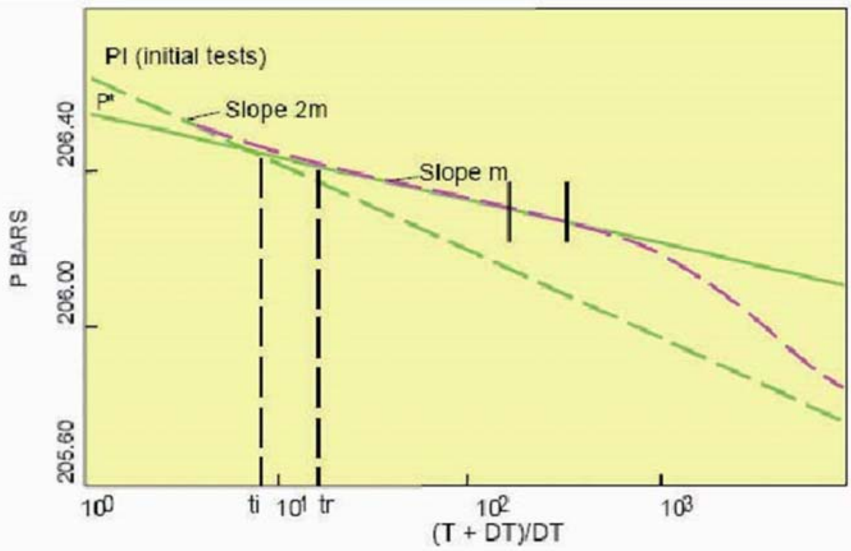
1. t small : $E_1 = 0$ slope of straight line $m = \dfrac{qB\mu}{4\pi kh}$

2. t large : $E_1 = \ln\dfrac{Kt}{4d^2} + 0.81$

$$P_i - P_{wf}(t) = 2m\left(\ln\frac{Kt}{r_w^2} + 0.81 + \ln\frac{r_w}{2d}\right)$$

slope straight line 2m

WARNING! slope straight line 2m $\cancel{\rightarrow}$ Fault



FAULT DISTANCE

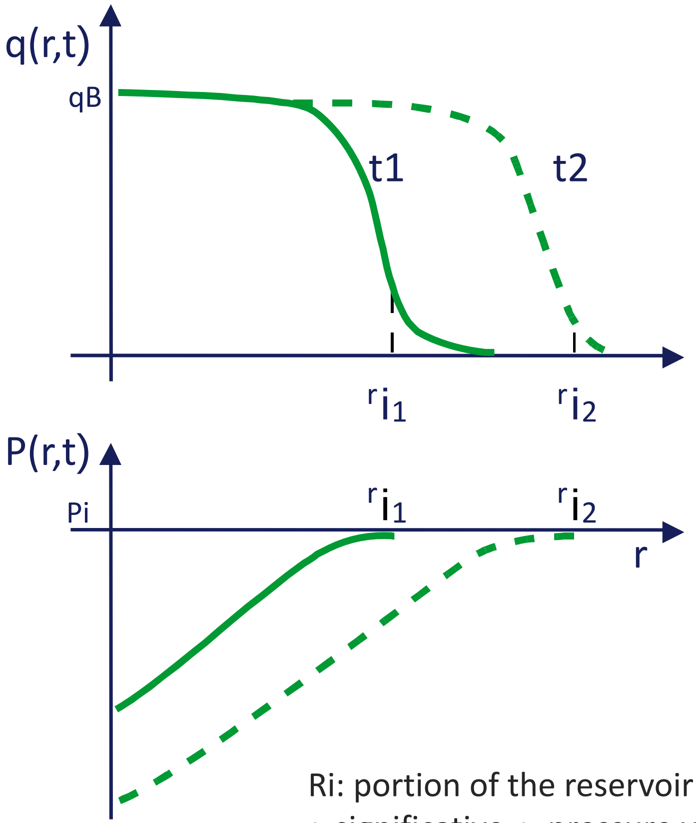
intersection of slope straight lines m and 2m

$$d = 0.012\sqrt{\frac{k\,ti}{\phi\mu ct}}$$

radius of investigation

$$d = 0.032\sqrt{\frac{k\,tr}{\phi\mu ct}}$$

Radius of investigation



$$q = q B e^{\frac{-r^2}{4Kt}}$$

Radius of investigation

$$\frac{\partial^2 p}{\partial t^2} = 0 \Longrightarrow \frac{r^2}{4Kt} = 1$$

$$r_i = 0{,}032 \sqrt{\frac{kt}{\Phi \mu ct}} \quad \text{(us)}$$

Ri: portion of the reservoir that has experienced a « significative » pressure variation

Notes

Analysis
with the TYPE CURVES
and
DERIVATIVE Analysis

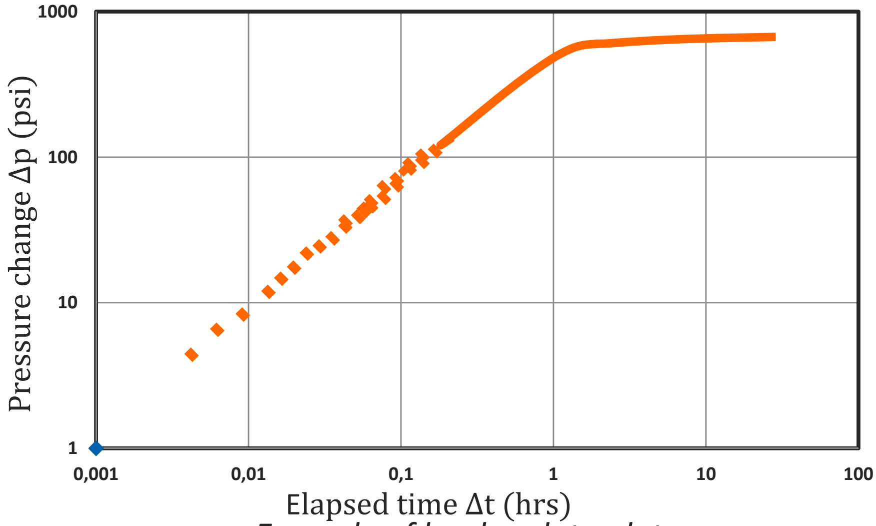
Conventional methods

The conventional methods (including the Horner's method) are simple, but very limited for diagnosing reservoir and well behavior:

- **Drawbacks:**
  - Straight-Line Region recognition may not be easy.
  - Only straight-Line Region data points can be used for interpretation
  - Flow regime diagnostic
  - Limited number of models

Log-log Scale

- For a given flow period, the change in pressure, Δp, is plotted on a log-log scale versus the elapsed time Δt

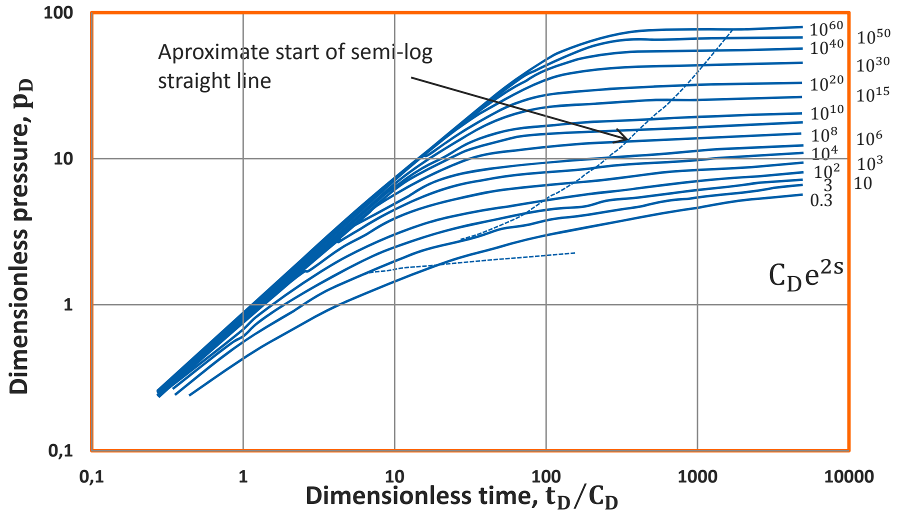


Example of log-log data plot

- The log-log analysis is a global approach as opposed to straight line methods that make use of only one fraction of the data, corresponding to a specific flow regime.

Log-log pressure type curves

- By comparing the log-log data plot to a set of theoretical curves (type curves), the model that best decribed the pressure response can be identified



Pressure type curve: well with WBS & skin, in an homogeneous infinite acting reservoir

- Usually the theoretical curves are expressed as **dimensionless term**

$$p_D = \frac{1}{2}\left[\mathrm{Ln}\left(\frac{t_D}{C_D}\right) + 0.80907 + \mathrm{Ln}\left(C_D e^{2S}\right)\right]$$

Log-Log Type curve

Dimensionless terms

- Dimensionless pressure, time and WBS coefficient are defined as:

$$p_D = \frac{kh}{141.2qB\mu}\Delta p \leftrightarrow \log p_D = \log \Delta p + \log\left(\frac{kh}{141.2qB\mu}\right)$$

$$t_D = \frac{0.000264k}{\phi\mu c_t {r_w}^2}\Delta t \leftrightarrow \log t_D = \log \Delta t + \log\left(\frac{0.000264k}{\phi\mu c_t {r_w}^2}\right)$$

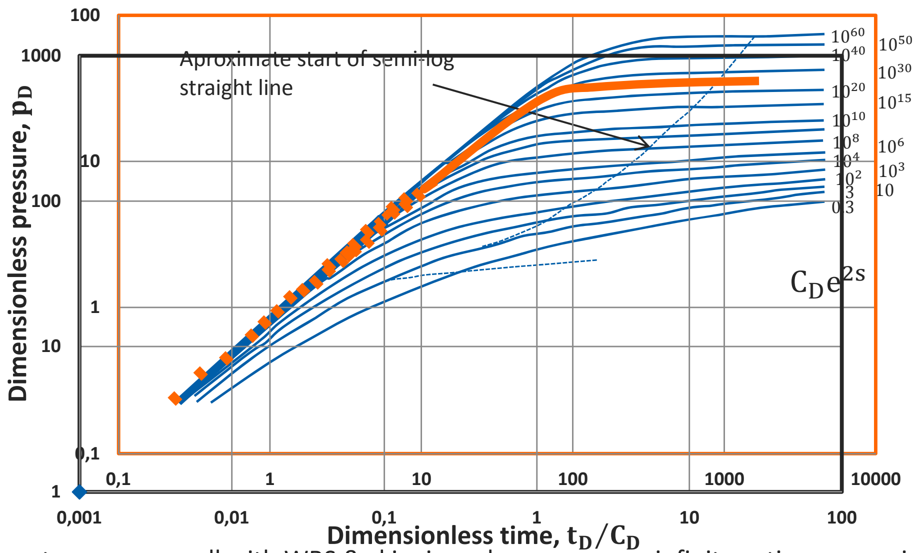
$$C_D = \frac{0.8936C}{\phi c_t h {r_w}^2} \leftrightarrow \log C_D = \log C + \log\left(\frac{0.8936}{\phi c_t h {r_w}^2}\right)$$

$$C_D e^{2S} = \frac{0.8936C}{\phi c_t h {r_w}^2}e^{2S}$$

- Gringarten proposed using a dimensionless time group defined as:

$$\frac{t_D}{C_D} = 0.000295\frac{kh}{\mu}\frac{\Delta t}{C} \leftrightarrow \log\left(\frac{t_D}{C_D}\right) = \log\left(\frac{\Delta t}{C}\right) + \log\left(0.000295\frac{kh}{\mu}\right)$$

Type curve matching



Pressure type curve: well with WBS & skin, in an homogeneous infinite acting reservoir

Pressure match

$$PM = \frac{p_D}{\Delta p}$$

$$\mathbf{kh} = 141.2qB\mu(PM)$$

Time match

$$TM = {(t_D/C_D)}/_{\Delta t}$$

$$C = 0.000295\frac{kh}{\mu}\left(\frac{1}{TM}\right)$$

The skin factor is evaluated from $C_D e^{2S}$ of the curve match

$$S = \frac{1}{2}\text{Ln}\frac{(C_D e^{2S})_{Match}}{C_D}$$

Derivative method

Based on the fact that the change in pressure is more meaningful than the pressure itself, the introduction of the derivative method has brought a significant improvement to the log-log analysis:

- **Proper handling of multi-rate tests / production**
- **Numerous Well and Reservoir models available**
- **Flow regime diagnostic analysis**

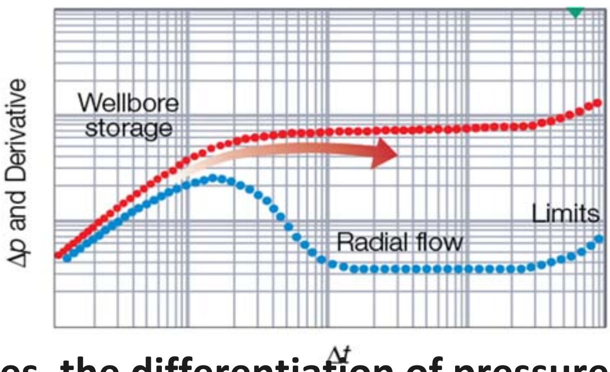
Interpretation history: the advent of derivatives

- **Introduced in the 1980s by D. Bourdet, the derivative analysis is still today a cornerstone in pressure transient analysis**
- **It is defined as**

$$P_D^{'} = \frac{dP_D}{dLn\frac{t_D}{c_D}} = \frac{t_D}{c_D} * \frac{dP_D}{d\frac{t_D}{c_D}}$$

(for a draw-down test)

- **Excellent tool for the identification of flow regimes and reservoir models**



- **But sometimes, the differentiation of pressure data leads to significant noise**

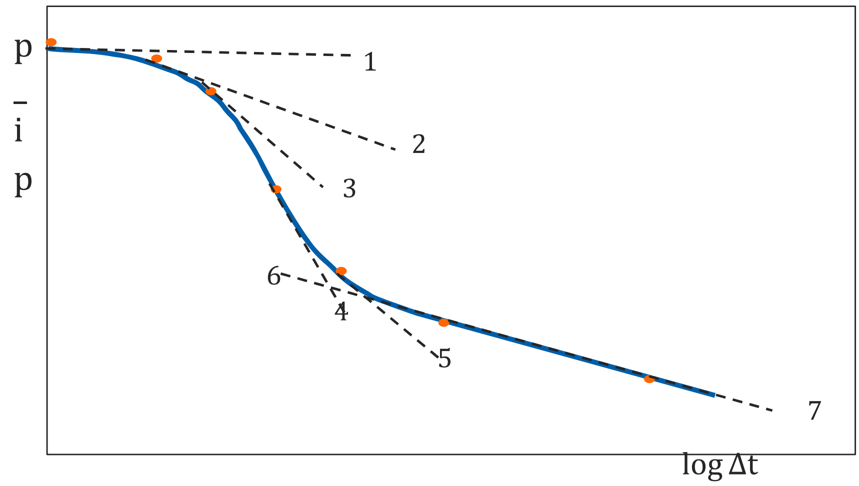
Derivative analysis

- The idea is to get a reliable way of recognizing the Infinite Acting Radial Flow (IARF)
- This can be achieved by the use of the pressure derivative
- The Bourdet Derivative is the slope of the semilog plot displayed on the log-log plot
  - For the first drawdown:
    $$\Delta p' = \frac{dp}{d\ln(\Delta t)} = \Delta t \frac{dp}{dt}$$
  - For a shut-in after a single drawdown:
    $$\Delta p' = \frac{dp}{d\ln\left(\frac{t_p \Delta t}{t_p + \Delta t}\right)} = \frac{t_p + \Delta t}{t_p} \Delta t \frac{dp}{dt}$$
  - In the more general multi-rate case, and in particular for shut-ins:
    $$\Delta p' = \frac{dp}{dsup(\Delta t)}$$

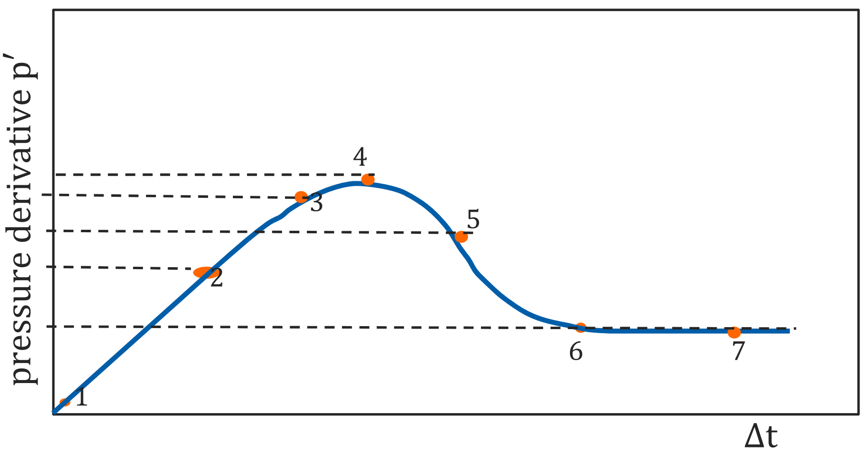
    Where

    Superposition time; $\sup(\Delta t) = \sum_{i=1}^{n-1} \frac{q_i - q_{i-1}}{q_n - q_{n-1}} \log(t_n - t_i + \Delta t) + \log \Delta t$

Pressure derivative



Semi – log plot



Pressure Derivative plot on a log – log scale

General expression of the derivative, in case of a build-up following a multi-rate flow period:

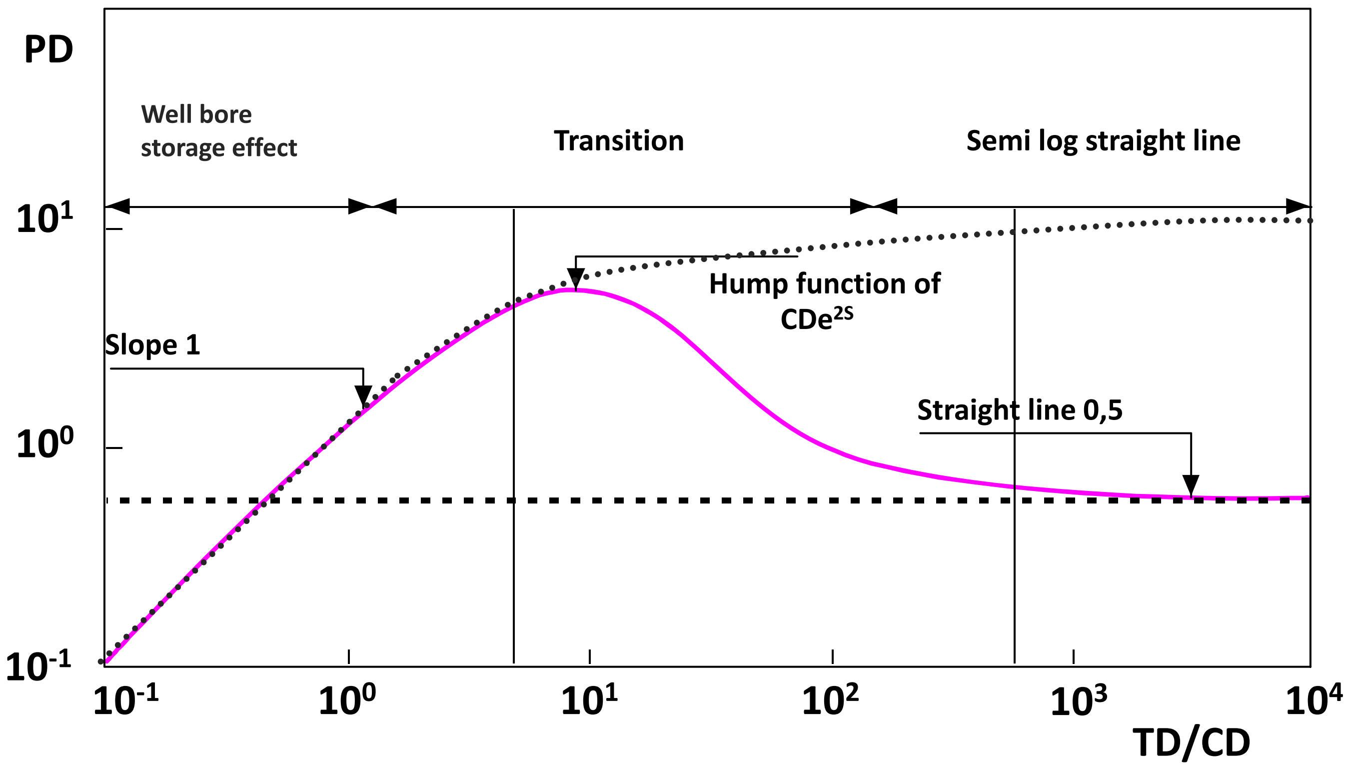
- **The expression of the derivative is calculated versus the « function of time in radial flow in transient flow »**
  - **Pressure build-up following a constant flow rate period**

$$P'_D = \frac{dp_D}{d\mathrm{Ln}\,\dfrac{tp + \Delta t}{\Delta t}}$$

  - **Multirate flow period followed by a build-up**

$$P'_D = \frac{dp_D}{d\displaystyle\sum_{i=1}^{n} \frac{qi}{qn} \mathrm{Ln}\,\frac{tn - t_{i-1} + \Delta t}{tn - t_i + \Delta t}}$$

Derivative



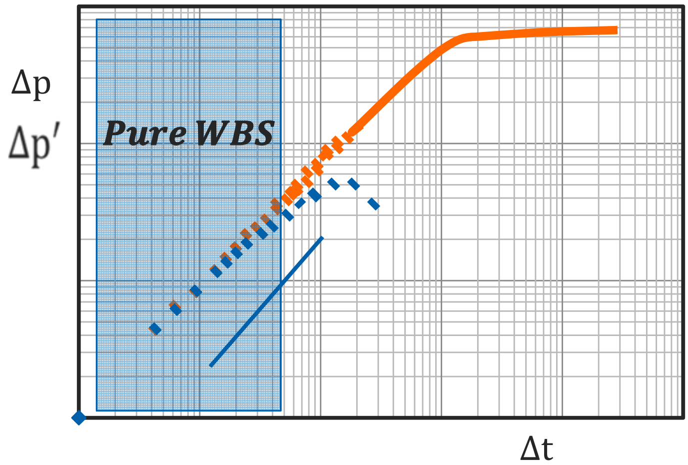
Derivative type curve

Wellbore storage

- The derivative is plotted on log-log coordinates, versus the elapsed time Delta t since the beginning of the shut-in period .
- During pure WBS regime, the change in pressure ΔP and the derivative of the change in pressure ΔP’ follow a single straight line of slope = 1; both curves superimpose.

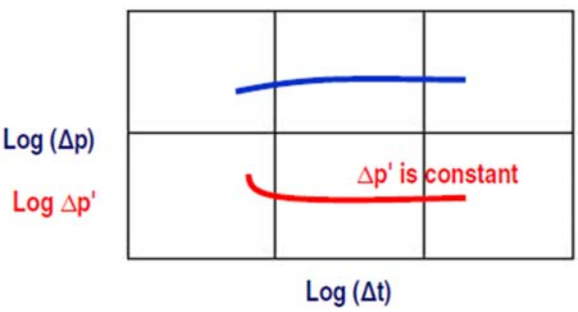
$$\Delta p = \frac{QB}{24C}\Delta t$$

$$\Delta p' = \frac{dp}{d\ln(\Delta t)} = \frac{QB}{24C}\Delta t$$



Pressure - Derivative log-log plot

- Later, the derivative stabilizes, depending on the flow regime.
- The derivative curve becomes a diagnostic tool to identify different types of flow regimes:
- The derivative becomes constant (i.e. slope = 0) when the IARF Regime is reached.



$$\Delta p' = 70.6\frac{qB\mu}{kh}$$

In dimensionless terms:

$$\frac{dp_D}{d\ln(t_D/C_D)} = 0.5$$

Derivative type curve

Radial flow

- **When IARF occurs:**

$$\Delta p = 162{,}6\frac{QB\mu}{kh}\left[\log\Delta t + \log\frac{k}{\phi\mu c_t {r_w}^2} + 3.23 + 0.87S\right]$$

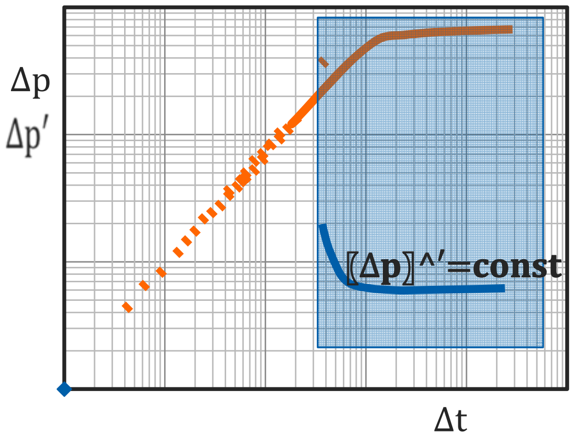
$$\boxed{p_D = \frac{1}{2}\left[\mathrm{Ln}\left(\frac{t_D}{C_D}\right) + 0.80907 + \mathrm{Ln}\left(C_D e^{2S}\right)\right]}$$

  - The derivative becomes constant:

$$\Delta p' = \frac{dp}{d\ln(\Delta t)} = 70.6\frac{QB\mu}{kh}$$

  - In dimensionless terms, the derivate stabilizes at 0.5

$$p'_D = \frac{dp_D}{d\ln\left(\frac{t_D}{C_D}\right)} = \frac{1}{2}$$



Pressure - Derivative log-log plot

- **The derivative, used in conjunction with the pressure plotted on a log-log scale, is a powerful diagnostic tool:**
  - **During Wellbore storage, the derivative and the pressure, follow a straight line with a slope of 1.**
- **The majority of the later flow regimes during a well test, can be represented by:**
  - **a linear expression of the pressure versus the logarithm of time**
  - **or by a linear expression of the pressure versus a power function of time**

Pressure - Derivative log-log plot

- **When the expression of flow is a logarithmic function:**
- **The derivative stabilizes as a horizontal with a value a on the y-axis:**

$$P_D = a \, \mathrm{Ln}\left(\frac{tD}{cD}\right) + b$$

$$P'_D = a$$

$\Longrightarrow$ Straight line with y-axis value = **a**

Pressure - Derivative log-log plot

- **When the expression of flow is a power function:**
- **The derivative stabilizes as straight line with slope n :**

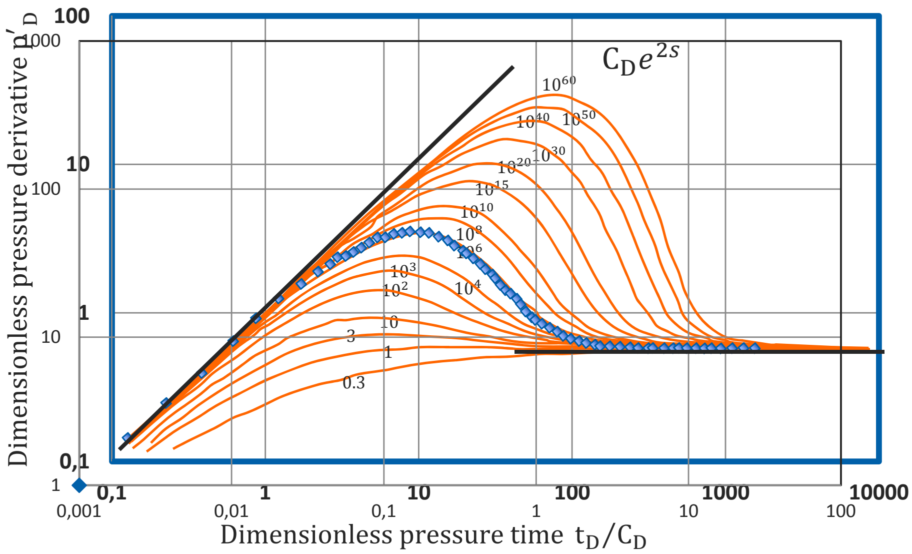
$$P_D = a \left(\frac{tD}{cD}\right)^n + b$$

$$P'_D = \frac{dP_D}{d\mathrm{Ln}\frac{tD}{cD}} = \frac{tD}{cD}\,\frac{dP_D}{d\,\frac{tD}{cD}} = \frac{tD}{cD}\, a\, n \left(\frac{tD}{cD}\right)^{n-1}$$

$$P'_D = a\, n \left(\frac{tD}{cD}\right)^n \Longrightarrow \log P'_D = n \log \frac{tD}{cD} + cste$$

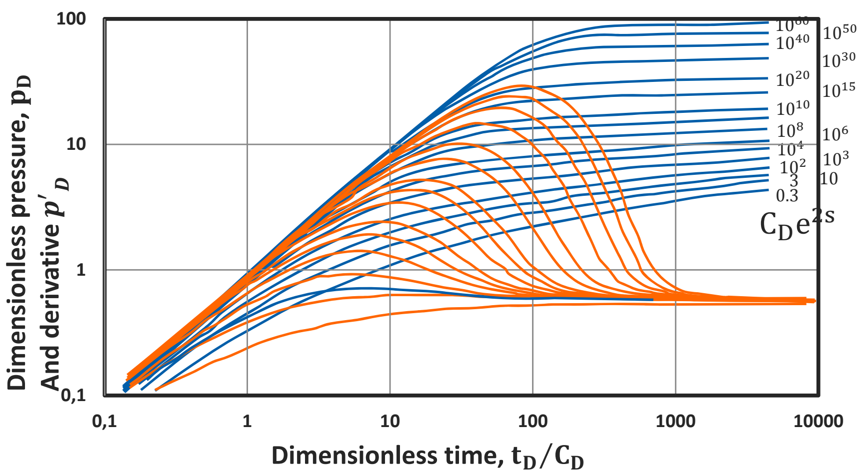
$\Longrightarrow$ Straight line with slope = **n**

Derivative type curve



Derivative type curve: well with WBS & skin, in an homogeneous infinite acting reservoir

Pressure and derivative type curve



Pressure & Derivative type curves: well with WBS & skin, in an homogeneous infinite acting reservoir

Derivative and other flow regimes

- Except for radial flow, during different flow geometries, the pressure changes with the elapsed time power $^1/_n$

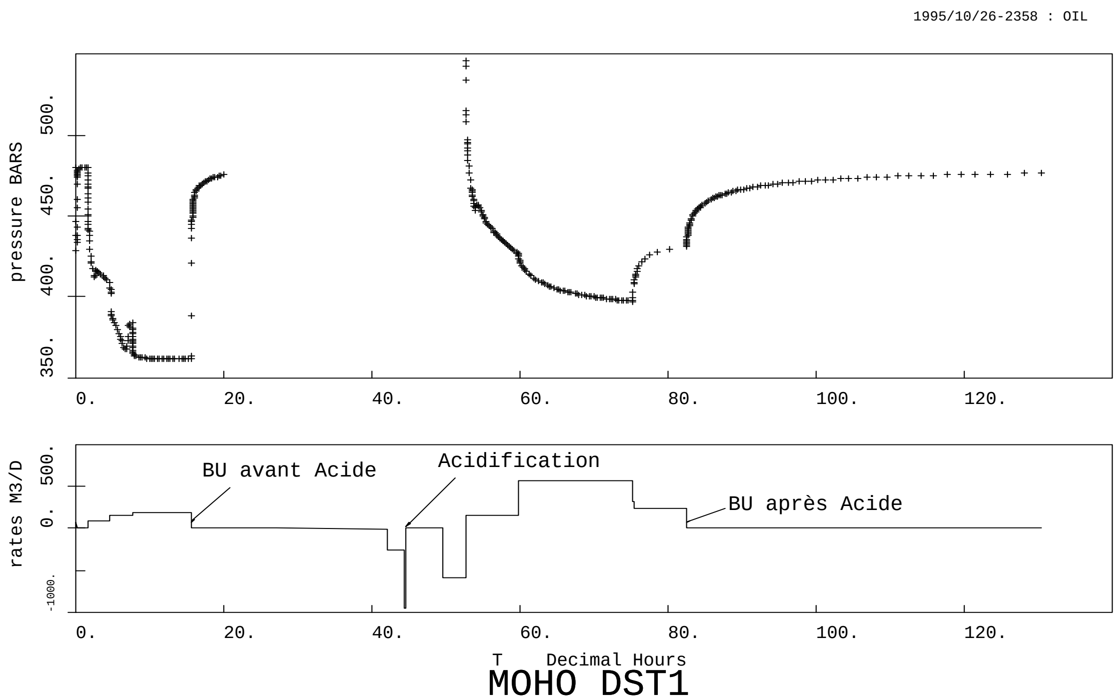
$$\Delta p = A(\Delta t)^{1/n} \quad \leftrightarrow \quad \log \Delta p = {}^1/_n \log \Delta t + \log A$$

$$\Delta p' = \frac{A}{n}(\Delta t)^{1/n} \quad \leftrightarrow \quad \log \Delta p' = {}^1/_n \log \Delta t + \log A$$

Model	Regime	Δp slope	$\Delta p'$ slope	Reponse
WBS	Storage	1	1	Wellbore
Fracture	Linear	0.5	0.5	Well
Fracture	Bilinear	0.25	0.25	Well
Limited Entry	Spherical	-	-0.5	Well
Homogeneous	IARF	-	0	Reservoir
Channels	Linear	0.5 (late time)	0.5	Boundary
Closed	PSS	1 (late time)	1	Boundary

Example

Complete production history



Notes

Reservoir BOUNDARIES

Reservoir BOUNADRIES

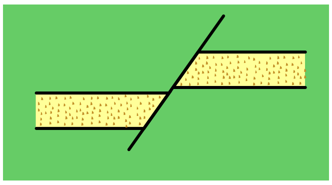
- **At the beginning of a well test, the compressible zone generated by the rate change moves away from the well without encountering any obstacle.**
  - **This represents the IARF, the Infinite Acting Radial Flow Regime**

- **When a limit is reached, it is marked by a characteristic pressure response at the well:**
  - Presence of one fault
  - Presence of two intersecting faults
  - Two parallel faults (the response will be the same in case of a channel)
  - Constant pressure limit
  - Closed reservoir
  - …

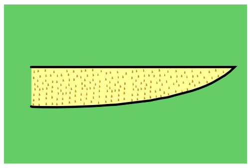
Different types of boundaries

Linear no flow boundary (e.g.: sealing fault)

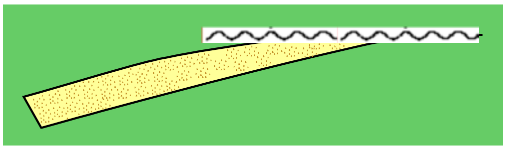
- The case of sealing linear fault has been first presented by Horne.
- This type of situation corresponds to several real situations:
  - A linear sealing fault



  - Rapid facies change / Reservoir pinchout



  - Unconformity

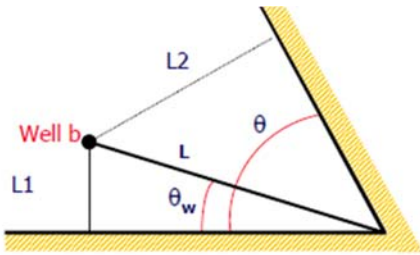


  - …
- It is treated by using the concept of a fictive mirror well

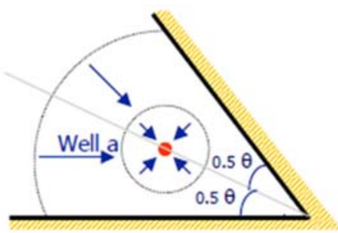
Different types of boundaries

Intersecting sealing faults

- The schematic geometry of this situation is presented:

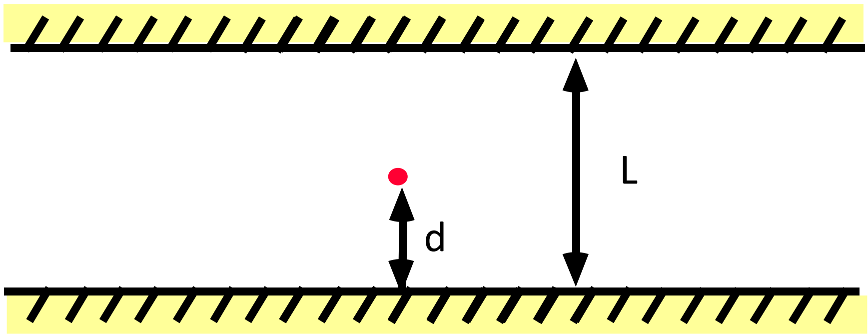


- This will result as a succession of the following flow regimes:
  - Radial flow
  - Fraction of radial flow



Different types of boundaries

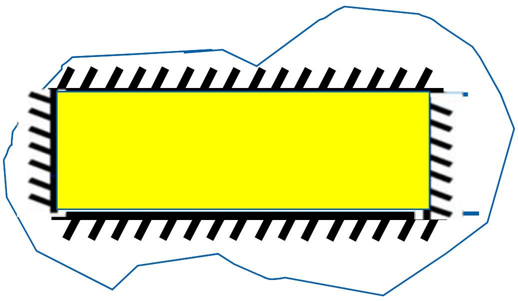
Two parallel sealing faults / Channel



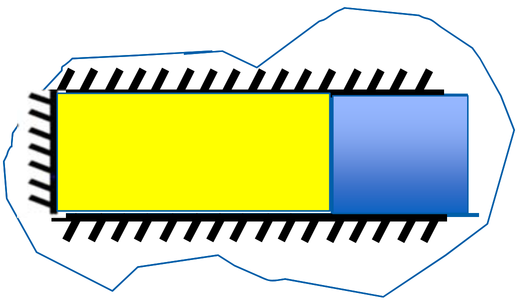
1. Radial Flow
2. Linear flow: when both infinite limits are reached

Different types of boundaries

Closed reservoir / mixed boundaries



Closed reservoir

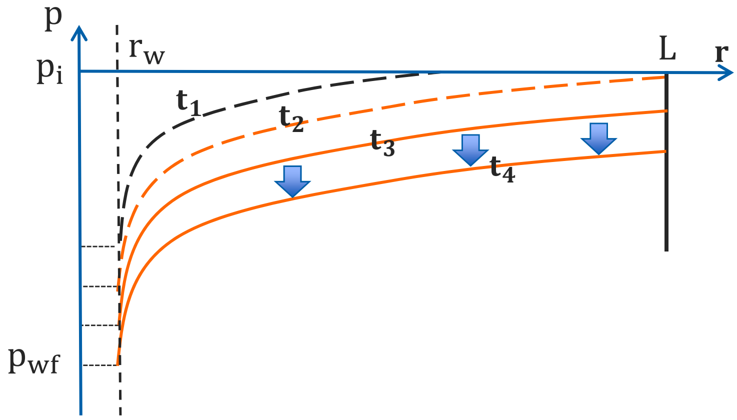


mixed boundaries

Closed reservoir:

Pseudo steady state regime

- In closed reservoirs, when all boundaries have been reached, the flow regime changes to pseudo steady state: i.e. at any point in the reservoir the rate of pressure decline is proportional to time



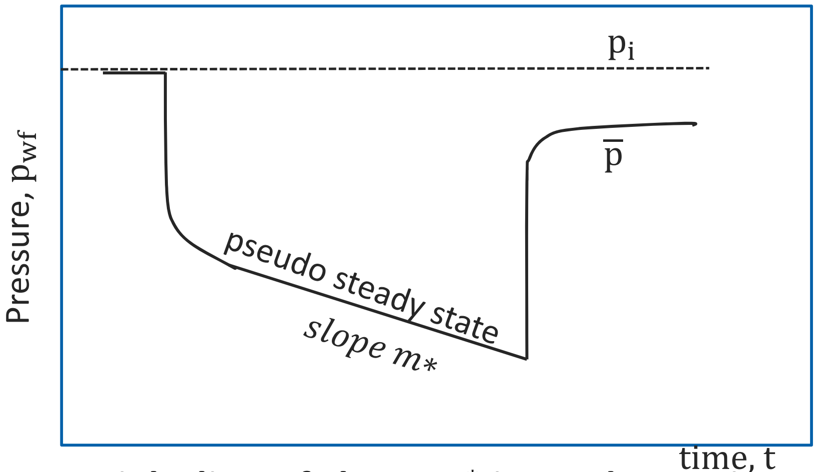
- **During the pseudo steady state the regime, the bottom hole pressure is a linear function of the elapsed time**

$$\boxed{p_{wf} = p_i - 0.234\frac{qB}{\phi c_t hA}\Delta t + 162.6\frac{qB\mu}{kh}\left[\log\frac{A}{{r_w}^2} - \log(C_A) + 0.351 + 0.87S\right]}$$

Pseudo steady state regime

Specialized analysis

- **During drawdown, the pseudo steady state regime is analyzed with a plot of pressure versus elapsed time on a linear scale**

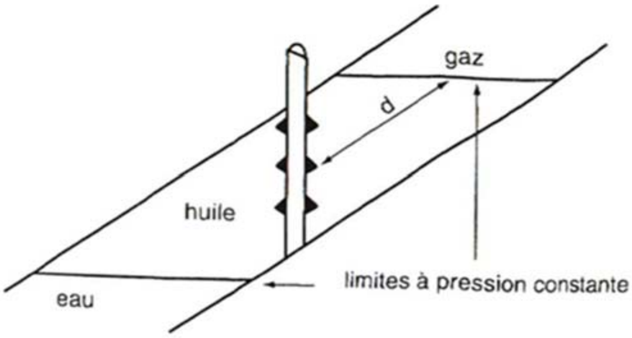


- **At late time, the straight line of slope m^* is used to estimate the reservoir pore volume ϕhA**

$$\boxed{\phi hA = 0.234\frac{qB}{c_t m^*}}$$

Constant pressure boundary

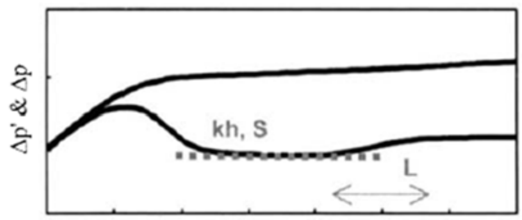
- A constant pressure boundary is typically the indication of the existence of a gas cap
- Or it can represent the situation of an oil zone with an aquifer with a high contrast of mobility (the water mobility in that case, being much greater than the oil mobility)



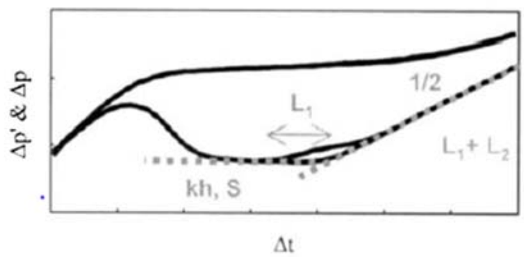
Examples of some usual log-log responses (after D. Bourdet)

Sealing fault (5.1)

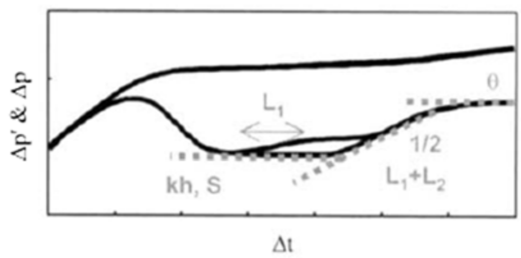
1 Radial, *kh* and *S*
2 Transition (mobility ↓), *L*
3 Hemi-radial



Channel (5.2)
Centered
1 Radial, *kh* and *S*
2 Linear, L_1+L_2
Off-centered
1 Radial, *kh* and *S*
2 Hemi-radial, L_1
3 Linear, L_1+L_2



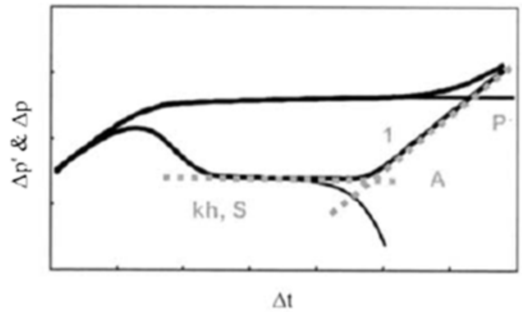
Intersecting faults (5.3)
Centered
1 Radial, *kh* and *S*
2 Linear, L_1+L_2
3 Fraction of radial, θ
Off-centered
1 Radial, *kh* and *S*
2 Hemi-radial, L_1
3 Linear, L_1+L_2
4 Fraction of radial, θ



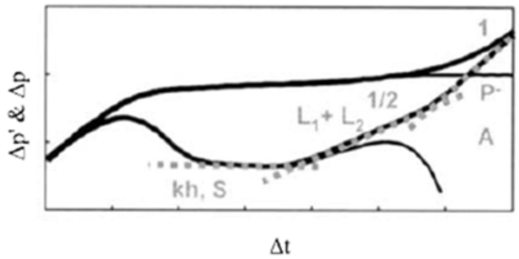
Examples of some usual log-log responses

(after D. Bourdet)

Closed system centered (5.4)
Drawdown
1 Radial, *kh* and *S*
2 Pseudo steady state, *A*
Build-up
1 Radial, *kh* and *S*
2 Average pressure, $\overline{p}$ and *A*



Closed channel (5.4)
Drawdown
1 Radial, *kh* and *S*
2 Linear, L_1+L_2
3 Pseudo steady state, *A*
Build-up
1 Radial, *kh* and *S*
2 Linear, L_1+L_2
3 Average pressure, $\overline{p}$ and *A*



Notes

RESERVOIR ASPECTS

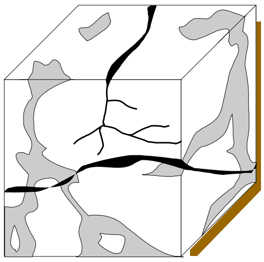
Reservoir aspects

- Different reservoir cases can be considered:
  - Homogeneous reservoir
  - Fractured reservoir
  - Two-layer reservoir
  - Radial composite reservoir
  - Linear composite reservoir

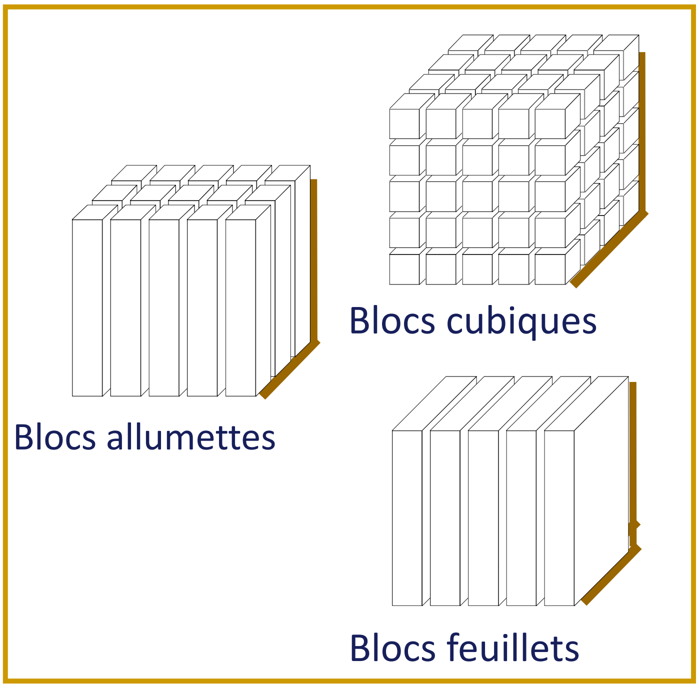
- For each case we can calculate the pressure and derivative response ; this response will be compared to the actual field measurements in order to elaborate the diagnostic.

Fractured reservoir

Fracture network in the reservoir

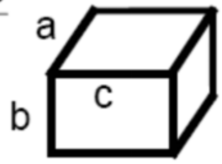


Different models to describe the reservoir response



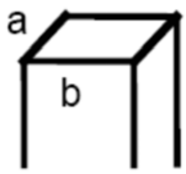
Geometry of the Matrix blocs

n = 3 CUBES



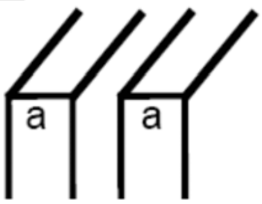
$$r_M = \frac{3\,abc}{2\,(ab + bc + ca)}$$

n = 2 MATCH BOXES



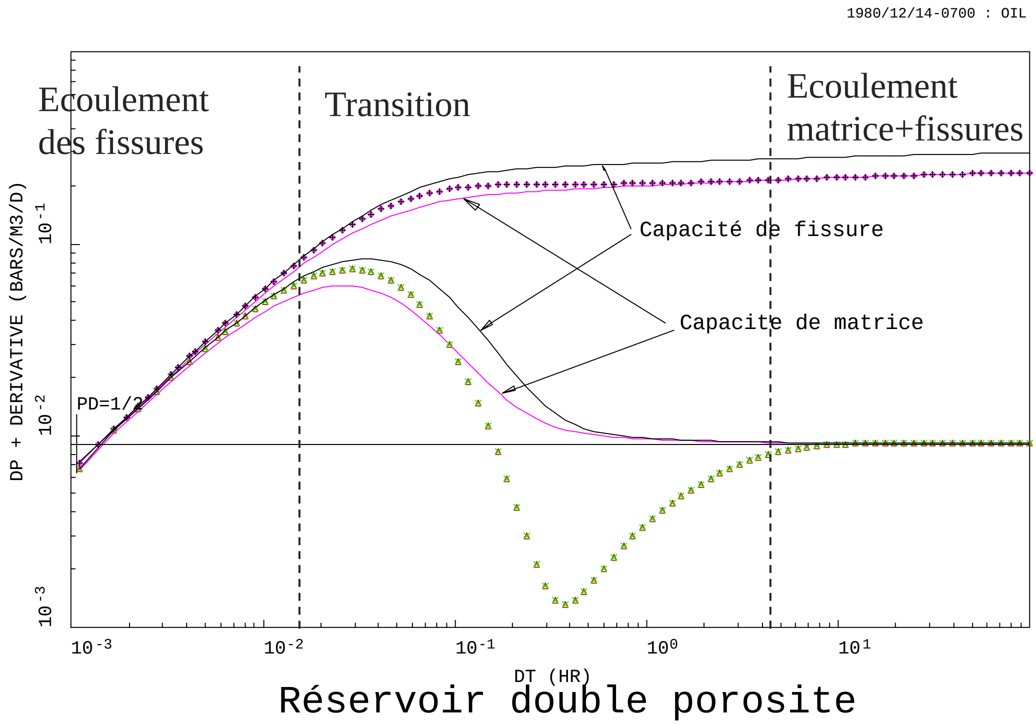
$$r_M = \frac{ab}{a + b}$$

n = 1 SHEETS

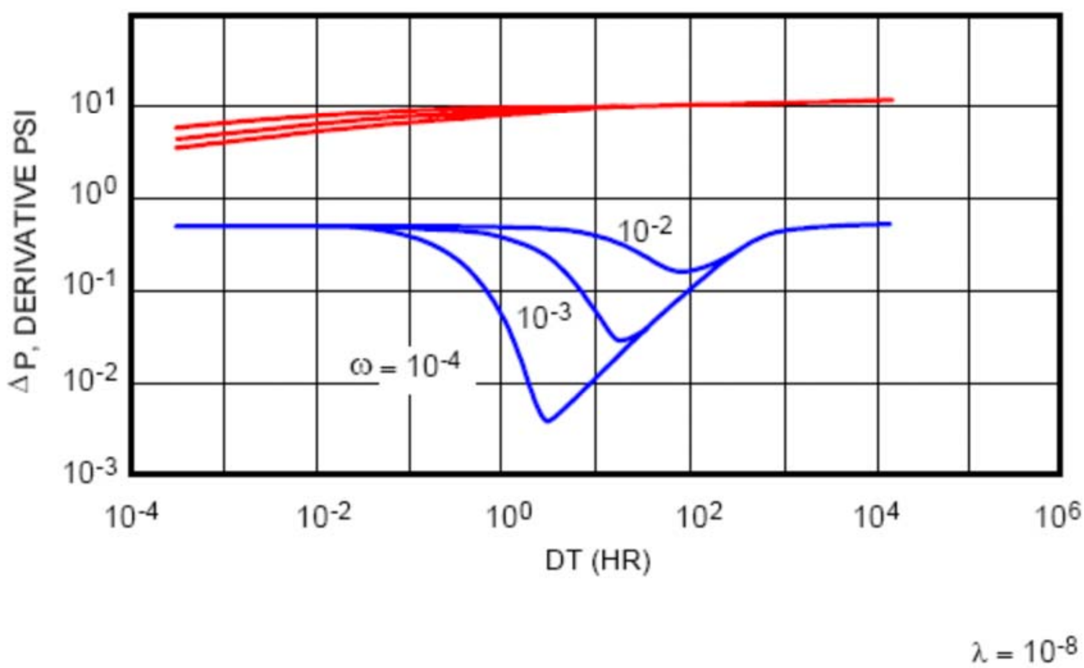


$$r_M = \frac{a}{2}$$

Double porosity derivative response



Storage capacity



Matrix – Fracture exchanges

- Matrix ➔ Fracture Flow

$$\lambda = \alpha r_w^2 \frac{k_m}{k_f}$$

Geometry of matrix blocks

$$\alpha = \frac{n(n+2)}{r_m^2}$$

Block sizes (1, 2, 3)

$$r_m = \frac{\text{Volume}}{\text{Surface}}\, n$$

Comments

- Often the effect of the well capacity hides the first 2 flows

➔ λ and ω impossible to determine

which is why downhole shut-in is recommended

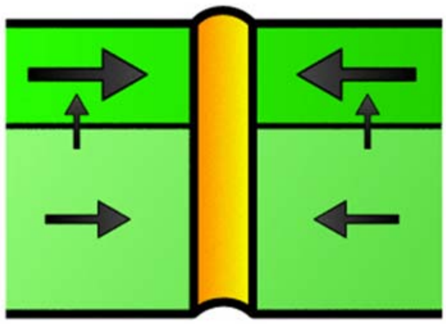
- Fracturing index

K test = 10 times K matrix

SKIN S<-2

Two-layer reservoir

- The reservoir is made of two layers with their own characteristics:
  - Net Thickness
  - Porosity
  - Saturation
  - Pore volume compressibility
  - Horizontal permeability
  - Vertical permeability
  - Skin



From Kappa

- The two layers are in hydraulic communication across a screen characterized by its vertical permeability

Notes

WELL ASPECTS

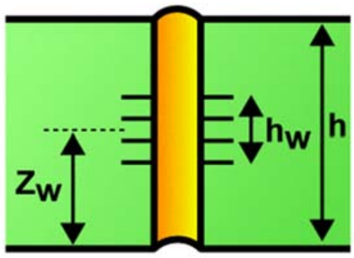
Well aspects / well models

- **The assumption made so far was that the well was a vertical well, fully penetrating the reservoir.**

- **Different well shapes or configurations need some additional calculations.**
  - Wells with partial penetration
  - Slanted wells
  - Horizontal wells
  - Fractured wells
  - …

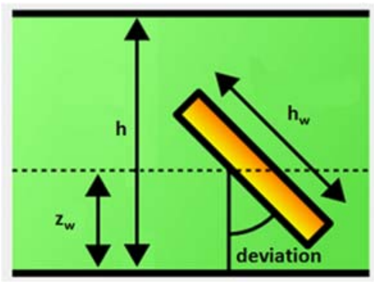
Partial penetration well

- **Different situations may occur:**
  - Limited perforation height

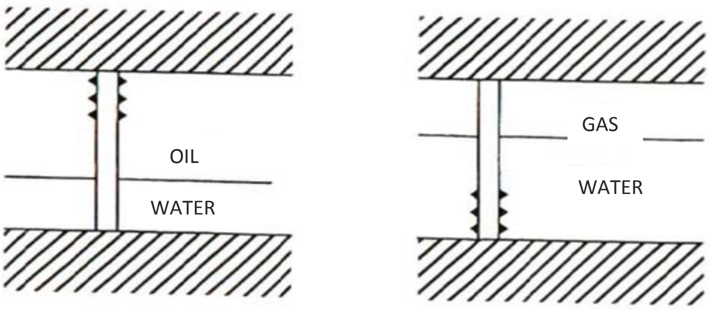


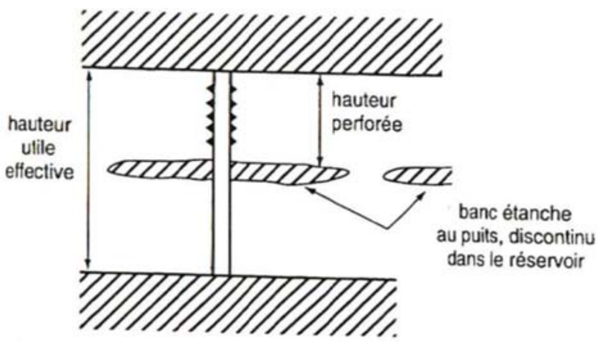
From Kappa

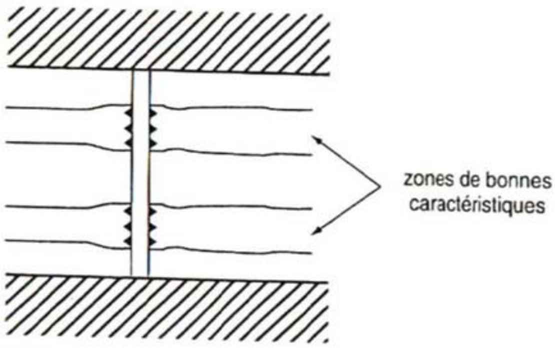
  - Slanted well



Well in partial penetration:





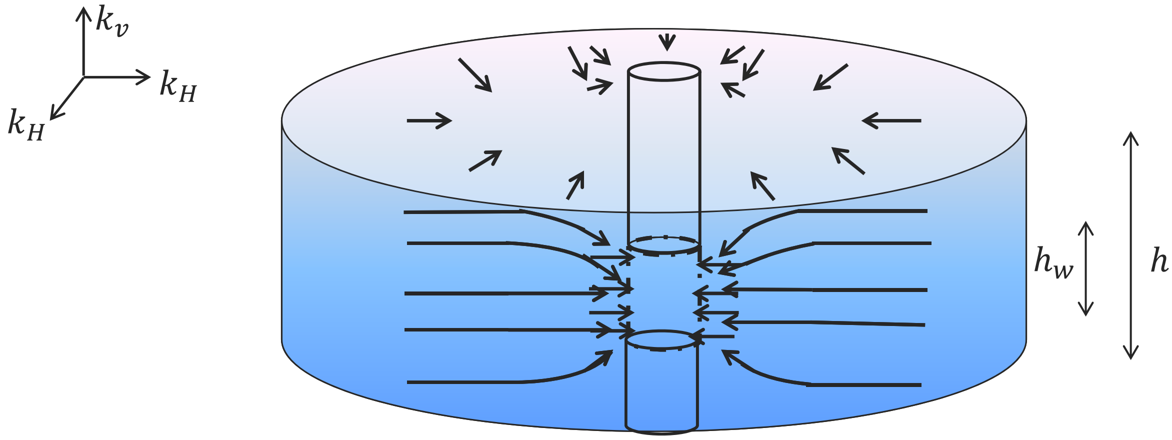


In: G Bourdarot

Well in partial penetration:

Spherical flow regime

- Spherical flow occurs when the flow streamlines converge to a point



Geometry of the flow lines: radial, spherical and radial flow regimes

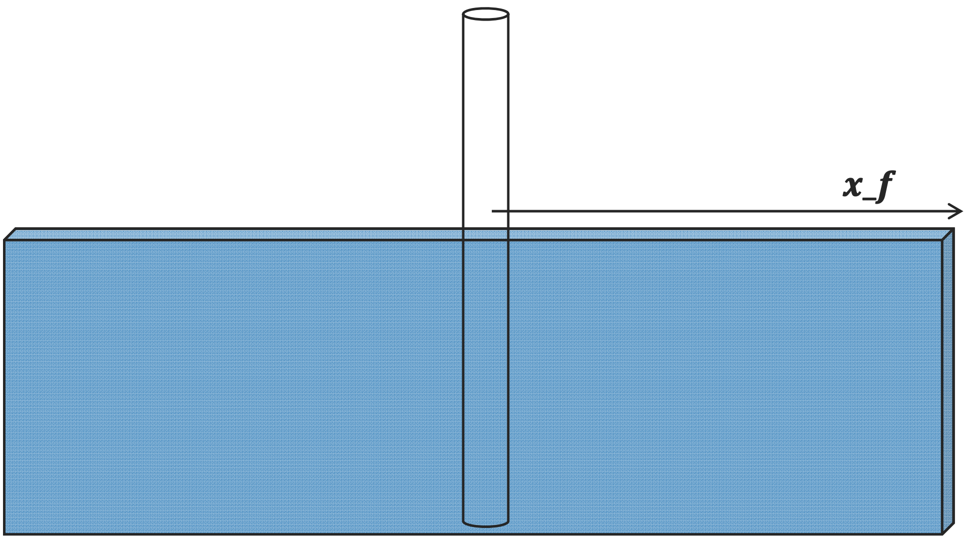
- **During the spherical flow regime, the pressure changes with** $1/\sqrt{\Delta t}$

$$\boxed{\Delta p = 70.6\frac{qB\mu}{k_s r_s} - 2452.9\frac{qB\mu\sqrt{\phi\mu c_t}}{{k_s}^{3/2}\sqrt{\Delta t}}}$$

Where k_s is the spherical permeability $\quad k_s = \sqrt[3]{k_x k_y k_z} = \sqrt[3]{{k_H}^2 k_v}$

Fractured well: infinite conductivity fracture

Linear flow regime



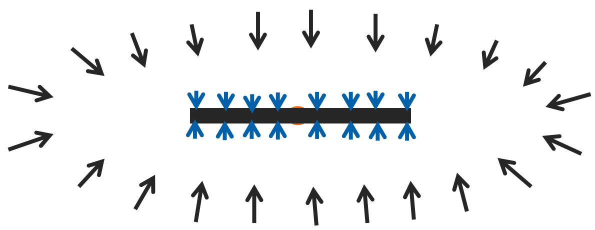
Fractured well. Fracture geometry

x_f is the half fracture length

Fractured well: infinite conductivity fracture

Linear flow regime

- At early time, the flow-lines are perpendicular to the fracture plane. This is called a linear flow regime



Geometry of the flow lines: linear and pseudo radial flow regimes

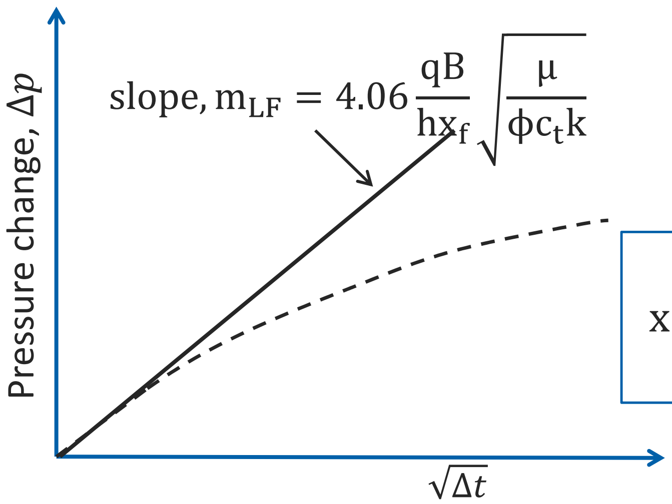
- During linear flow the pressure change is proportional to the square root of the elapsed time since the well was opened

$$\Delta p = 4.06 \frac{qB}{hx_f}\sqrt{\frac{\mu}{\phi c_t k}}\sqrt{\Delta t}$$

Fractured well: infinite conductivity fracture

Specialized analysis

- The linear flow regime can be analyzed with a plot of the pressure change Δp versus the square root of the elapsed time $\sqrt{\Delta t}$: the response follows a straight line of slope m_{LF}, intercepting the origin.

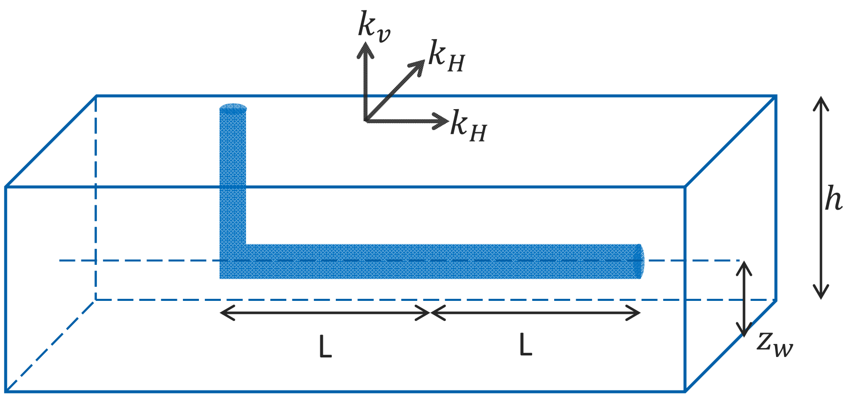


$$x_f = 4.06 \sqrt{\frac{\mu}{\phi c_t \mathbf{k}}} \frac{qB}{hm_{LF}}$$

Specialized plot of infinite conductivity fracture

Well model

Horizontal well

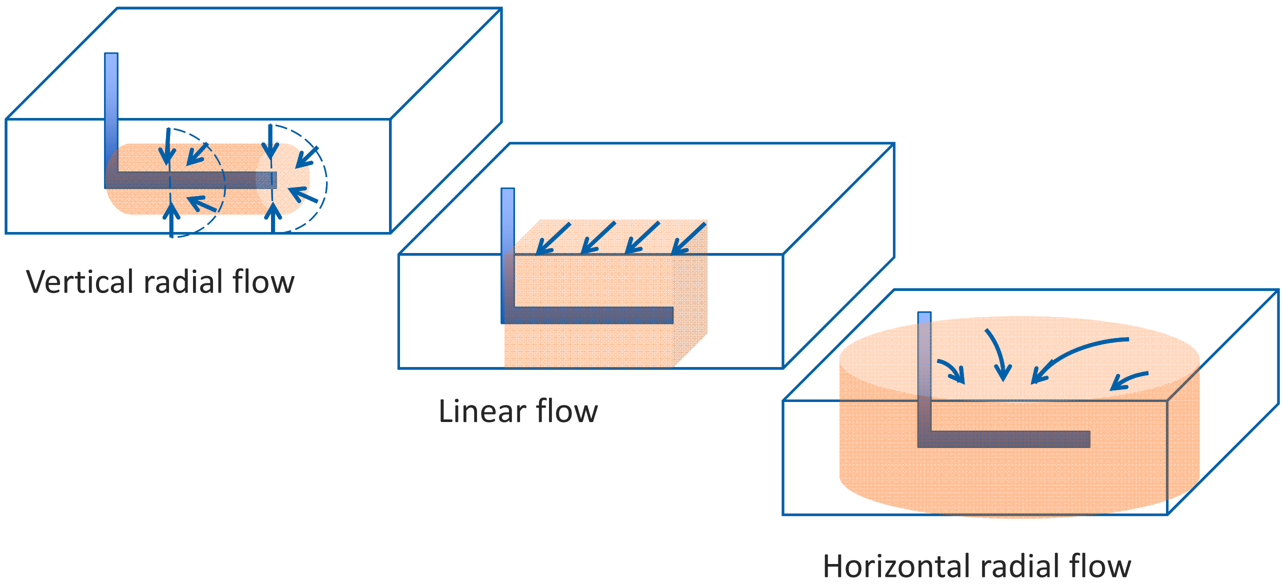


L- penetration half length
z_w- distance between the drain hole and the bottom sealing boundary
k_H- horizontal permeability
k_v- vertical permeability

N/B: The vertical part of the well is not perforated

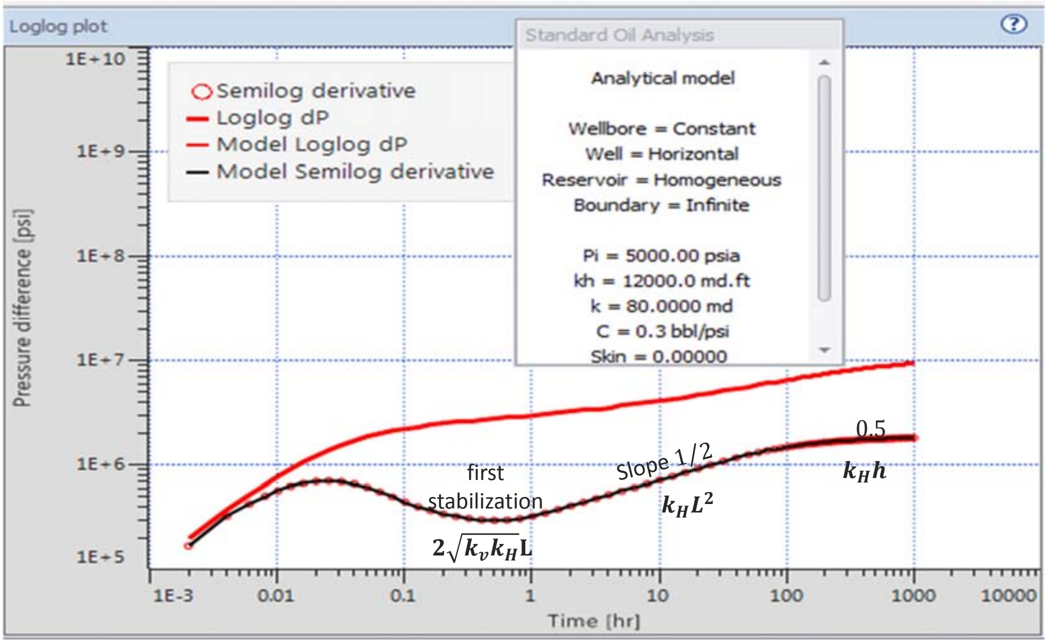
Horizontal well

Flow geometry to a horizontal well



Horizontal well

Log-log pressure and derivative response



Notes

GAS WELL TESTING

Different types of boundaries

Two major differences between gas well testing and liquid well testing:

- **Gas properties are highly pressure dependent**
  - The assumptions made for the liquid WTA are no longer valid.
  - The variations of gas properties are accounted for by using the concept of pseudo-pressure function
- **High gas rate may result in very high gas velocities around the wellbore**
  - The result will be additional pressure drop due to turbulent flow
  - This is accounted for by introducing a rate dependent skin effect

Gas well test analysis

- **Compressibility**
  - **Oil:** low, constant
  - **Gas:** High, depends on pressure

$$C = \frac{1}{P} - \frac{1}{Z}\left(\frac{\partial Z}{\partial P}\right)_T$$

  - **μ, z:** Function of pressure

Gas well testing and Pseudo-pressure

- **Solutions and methods developed for oil are valid for Gas when replacing**

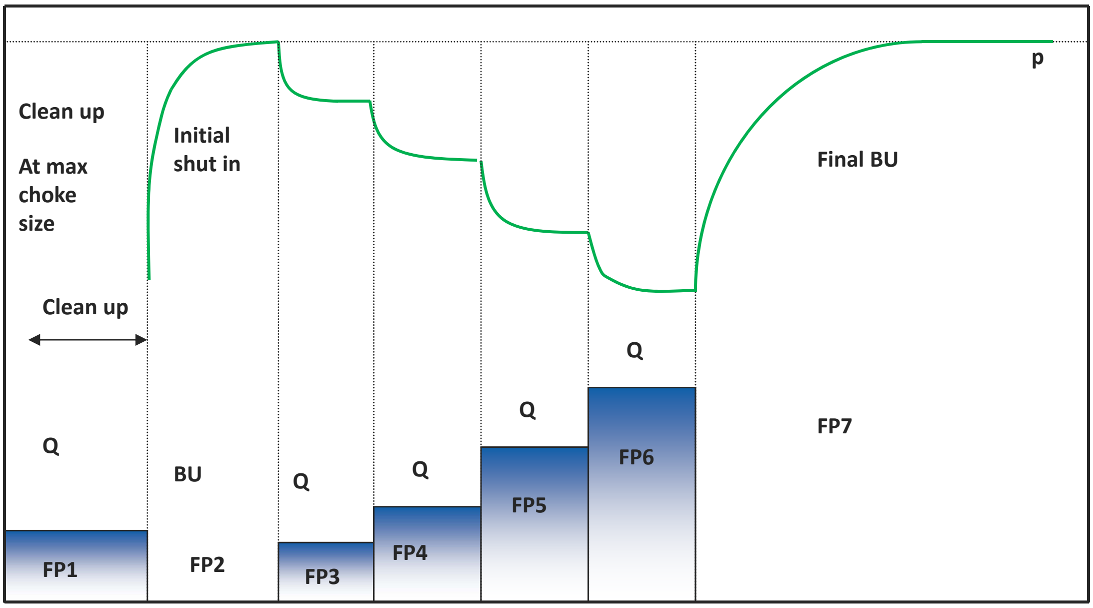
PRESSURE by

PSEUDO-PRESSURE

$$\Psi = 2\int_{P_o}^{P} \frac{P}{\mu Z} dP$$

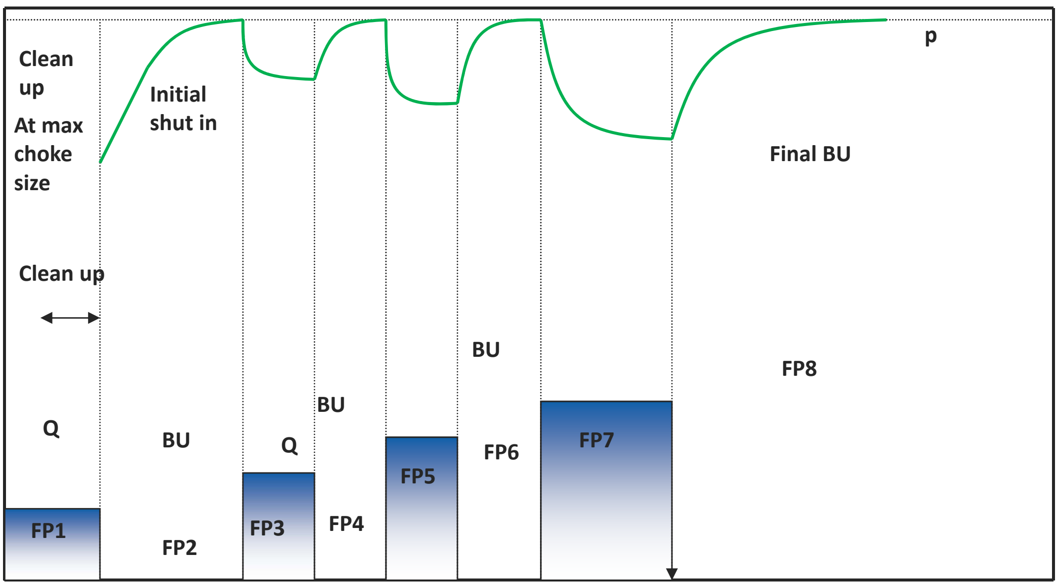
- **Z compressibility factor**
- **Ψ bar²/cp ou psi²/cp**
- **Ψ Computed with μ(p), Z(P)**

For high potential gas wells

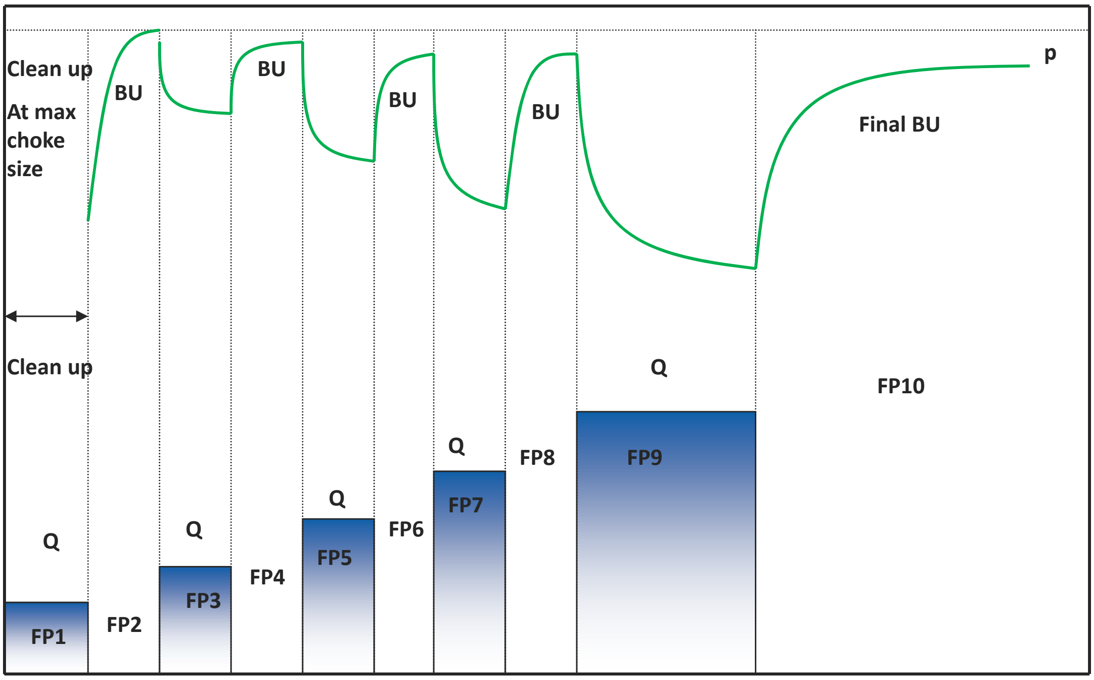


Flow after flow gas test (or back pressure test)

For low productivity gas wells



Isochronal Gas Test



Modified Isochronal Test

Notes

Interference tests
Pulse tests

Interference Tests

- **Interference tests involve several wells.**
  - An active well; this is the well where the rate is varying
  - An observation well, in which pressure is measured, is kept shut-in, non producing

- **Interference tests are performed in order to investigate if two or more wells are in communication, and to characterize this communication.**
- **Interference tests can also help us to evaluate horizontal permeability anisotropy.**

- **Measuring pressure in an observation well at a distance from the active well implies:**
  - The measured response is weak
  - There is a time lag before the emitted signal reaches the observation well

Interference Tests

Limitations

- **Weak pressure response in the observation well:**
  - Need to use high quality pressure gauges, with small drift and **high resolution**
  - Need to keep the observation well closed for the entire duration of the interference
  - Tides (maritime or terrestrial tides) could interfere with the measurement

- Signal measured with a time lag
  - Need to use high quality pressure gauges, with **small drift** and high resolution
  - Other wells may interfere with the measurement; it is essential that the rate of the other producers in the vicinity of the test be kept at constant value for the entire duration of the test.

- **Interpretation is made by using type curves (Theis type curves)**

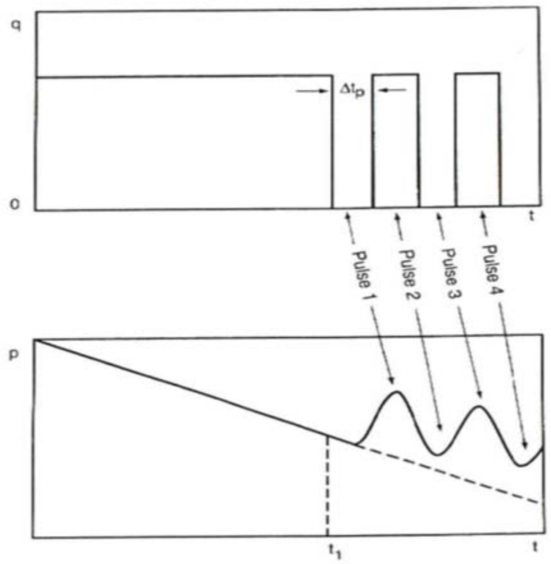
Pulse Tests

- **In a Pulse test the emitted signal consists in a succession of rate variations, typically alternating production periods followed by shut-in periods.**
- **In a Pulse test, each constant rate production period is short compared to the duration in an interference test:**
  - As a result, the pressure variations observed in the observation well are very small, with an order of magnitude of 0.1 to 0.01 psi.

- **Pulse test vs Interference test:**
  - Due to the short duration of each production period, the drift in pressure at the observation well can be neglected
  - The succession of rate variations results in several estimates of k/μ and of $\phi\mu c_t$
  - Pulse test are recommended in :
    - High hydraulic diffusivity values ($\eta = \frac{k}{\phi\mu c_t}$)
    - Short distance between observation and active wells.

Pulse Tests

- **The interpretation of a Pulse test is based on the analysis of two parameters:**
  - Pressure variation between a “pic” and a “low”
  - Time lag between a pulse and the corresponding “pic”



Rate variations at the **active well**

Pressure response at the observation at the **observation well**

Notes

Well Test DESIGN

Test Design

Need for test design

- **In the past, well test durations were based on rules of thumb for clean up, drawdown and build up periods.**
  - As a result engineering objectives were nor always met, and well test interpretations were difficult and limited.

- **The need for proper test design results from the combination of different evolutions:**
  - High operating costs
  - Need for detailed reservoir characterization and modeling

- **At the same time, software and computing capability have improved, as well as gauge accuracy and reliability,**
  - Rendering possible Proper test design to meet the objectives of data collection and analysis.

Well Test Design

- **A well test design is a draft of prognosis and Guide lines constitutive of a proposed Well Test Program.**

- **The proposed Well Test Program is then elaborated, taking into account:**
  - The different possible well / reservoir configurations
  - Time constraint
  - The available well test equipment.

Well Test Design

- **The different well / reservoir models envisaged are introduced in the well test analysis software and the pressure response is calculated as a function of the different flowrate histories.**

- **Test durations, limitations can be assessed and objectives can be assigned to the test.**

- **The equipment required is then defined and the final test program elaborated.**

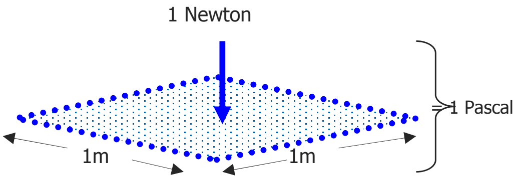
Well-test equipment

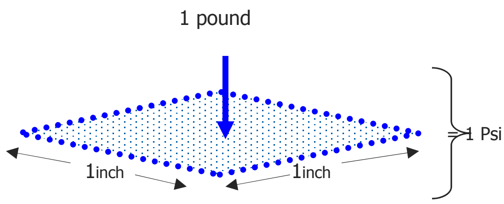
Test equipment

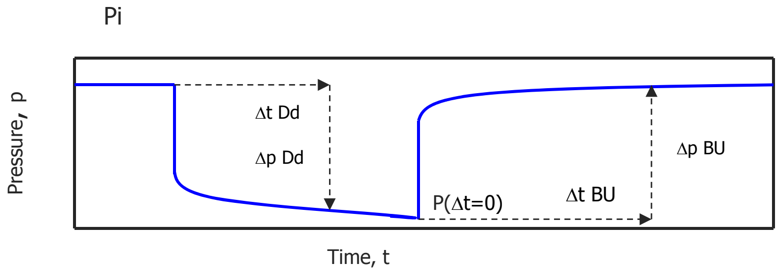
Different components

- **To test a well, the components required are:**
  - A well with permanent or temporary completion
  - A "pay zone"
  - Surface and downhole measuring equipment
  - Surface and downhole sampling equipment
- **Sometimes, additional equipment can be needed, such as Nitrogen, for N2 lift**
- **Sometimes, well treatment or stimulation (acid job) is needed**
- **Typical oil well test design**
  - A DST (DrillStem TEST) is a well test carried out with a specialized bottom assembly suspended by drill pipes
  - Conventional oil well tests are conducted by setting a provisional or permanent production completion

- **A pressure is a physical value:**
  - a force of 1 Newton over a surface of 1m² is defined as 1 Pascal
  - a weight of 1 pound exerted over a surface of 1 square Inch is a psi.







- A pressure gauge records the reservoir pressures during a well test
- It is located as close as possible to the formation.

Gauges are characterized by:

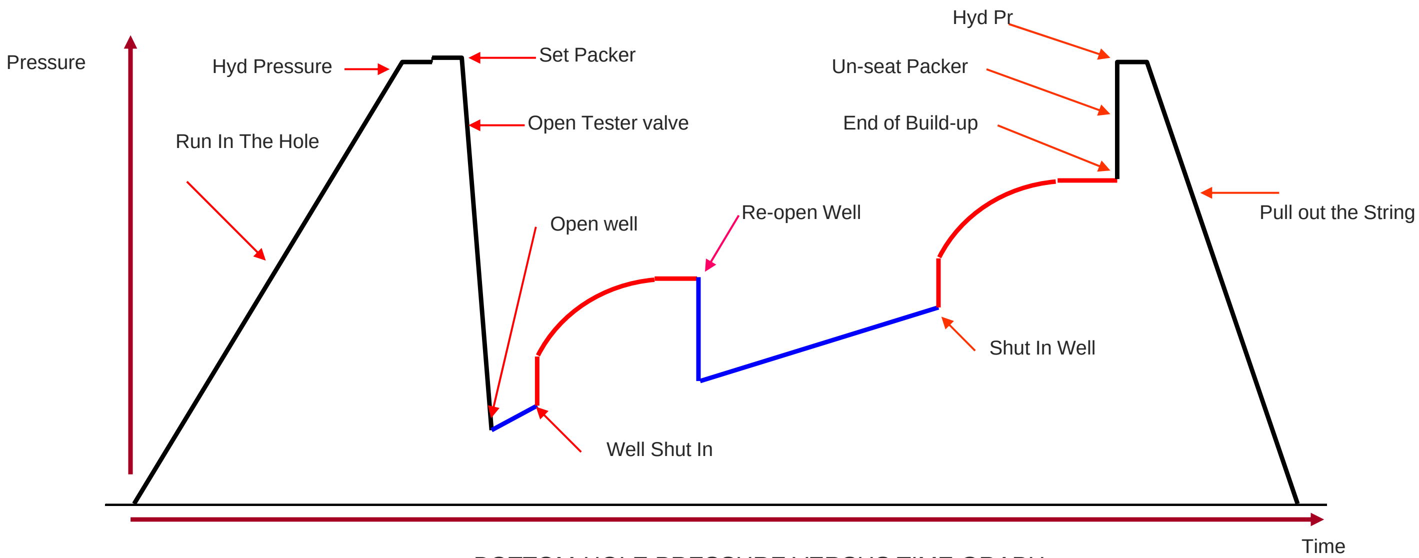
RANGE	ACCURACY	RESOLUTION	REPEATABILITY	DRIFT
pressure interval that can be acquired by the gauge	quality of the acquired pressure compared to a corresponding calibrated pressure	smallest pressure variation that can be detected by the gauge	Ability of a gauge to repeat the same pressure over a full pressure range cycle	deviation of the value of the recorded pressure

DST

A Drill Stem Test is conducted with a temporary well completion

A typical DST operation consist of:

- A short initial flow period
- An initial shut in period
- A second or final flow period
- A final shut in period



BOTTOM-HOLE PRESSURE VERSUS TIME GRAPH

Test equipment

Down-hole equipment

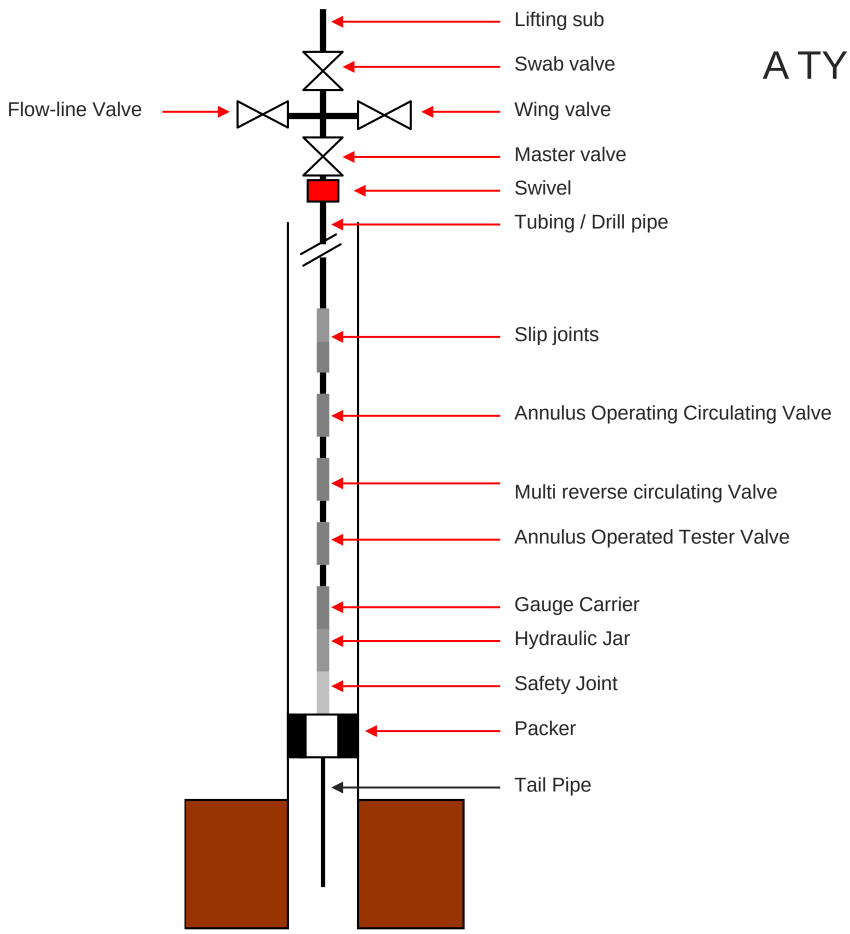
- **Minimum down-hole tools needed for a DST:**
  - Drill pipes / tubing
  - Slip joint
  - Single shot circulating valve
  - Tester valve
  - Jars
  - Gauge carrier
  - Safety joint
  - Packer
  - Tail pipe
- **And … tool box and spare parts !**

Down-hole equipment

- **Additional / optional tools:**
  - Down-hole safety valve
  - Multi-shot circulating valve
  - Full bore sampler
  - Bottom hole shut in tool
  - Pressure and temperature down-hole gauge with surface read out

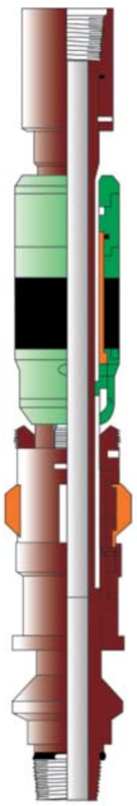
Down-hole test equipment

A TYPICAL DST STRING



Down-hole test equipment

PACKER



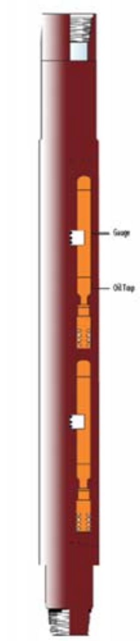
- To isolate the annulus from the reservoir.

OPERATION:

At setting depth, pick-up and rotate the test string at packer depth ¼

GAUGE CARRIER

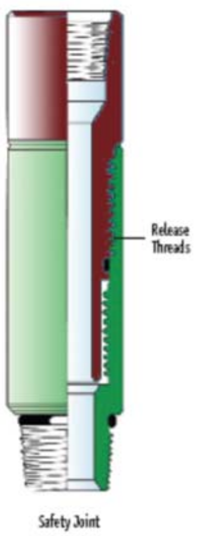
- A tool which can hold up to 4 memory pressure-temperature recorders
- It is placed below the tester valve to eliminate well bore storage effects during build up

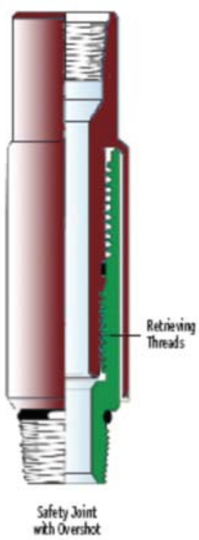


Down-hole test equipment

SAFETY JOINT

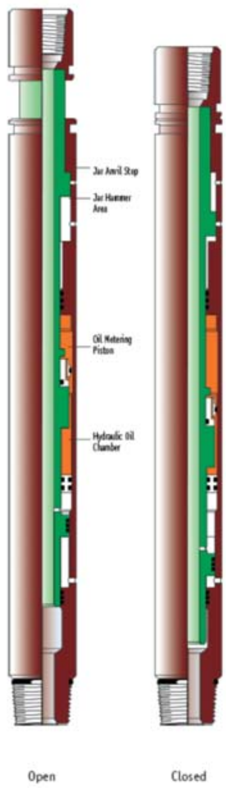
- Provides an emergency release between the test string and the packer



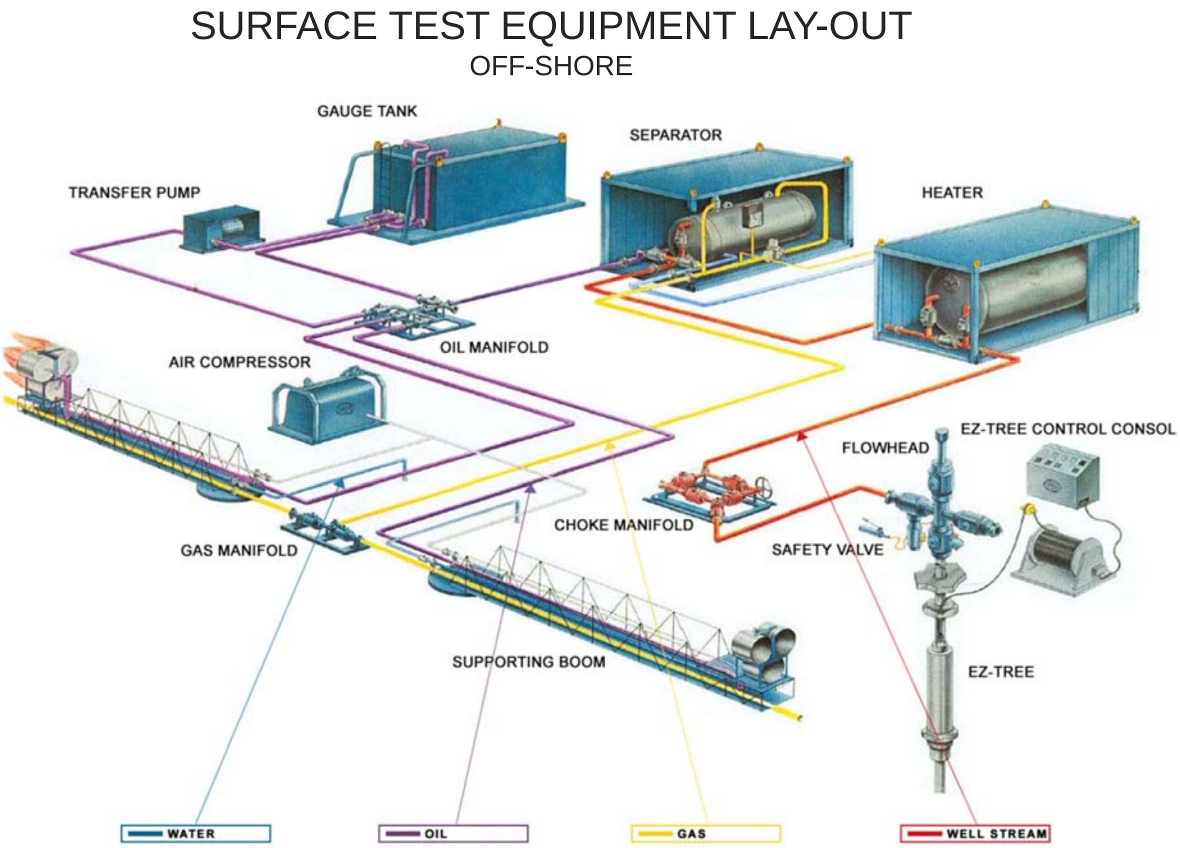


JARS

- A tool to free stuck packer
- When pulled at a certain pull, it releases a hammer that hits an anvil, and knocks the stuck string upwards



Surface test equipment



Surface test equipment

Main equipment

- Flow head
- Coflexip hose
- Data header
- Choke manifold
- Heater (optional)
- Steam exchanger
- Separator
- Oil manifold

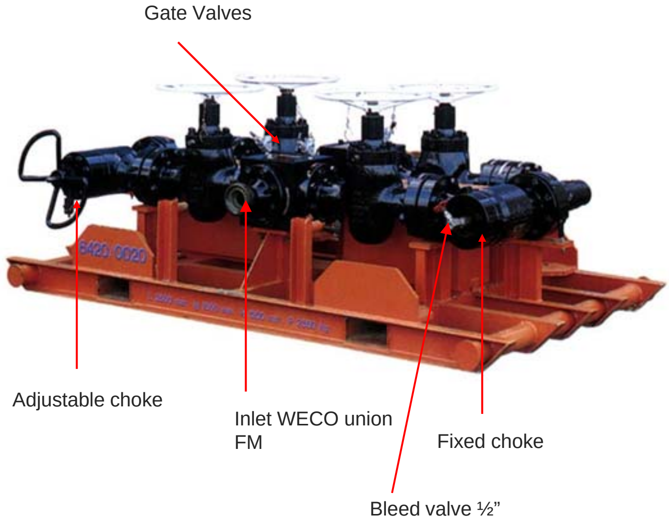
- Gas manifold
- Gauge tank (atm)
- Surge tank (press)

- Transfer pump
- Inter connecting piping
- Compressor

- Off-shore burners

- Booms

CHOKE MANIFOLD



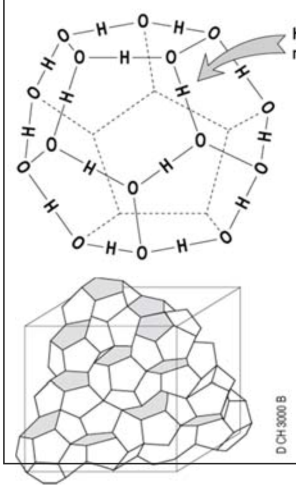
- **Is able to shut in the well and record surface shut in pressures.**
- **Able to regulate the flow, by the means of chokes.**
- **Fixed choke and adjustable choke**
- **WP:10 000 Psig**
- **ID 3”**

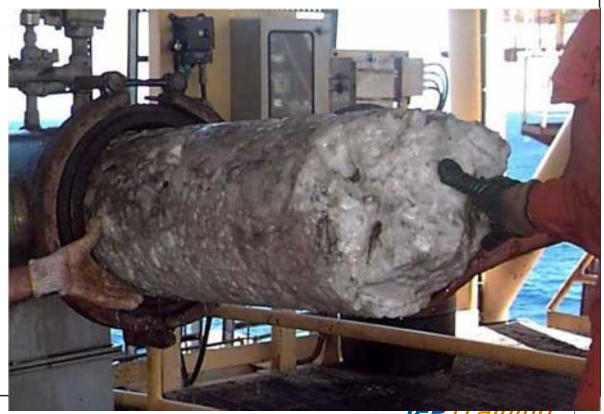
STEAM EXCHANGER

- **Used to heat up the well effluents and to lower the oil viscosity**
- **Prevents hydrates during gas well testing**

GAS RESERVOIR EFFLUENT	REQUIRED TREATMENTS	EXPORT GAS SPECIFICATIONS
MOSTURE • HC are water saturated at reservoir conditions	**DEHYDRATION** • Drying (Glycol : TEG)	**WATER DEW POINT** • France : < – 5°C at 80 bar. a. (Pmax of network)

HYDRATES





Notes

Sampling

Sampling objectives

Bottom hole sampling

Surface sampling

Sampling summary

Sampling objectives

- **The objective - and difficulty - is to obtain a sample of fluid that is identical (<u>truly representative</u>) of the reservoir fluid.**

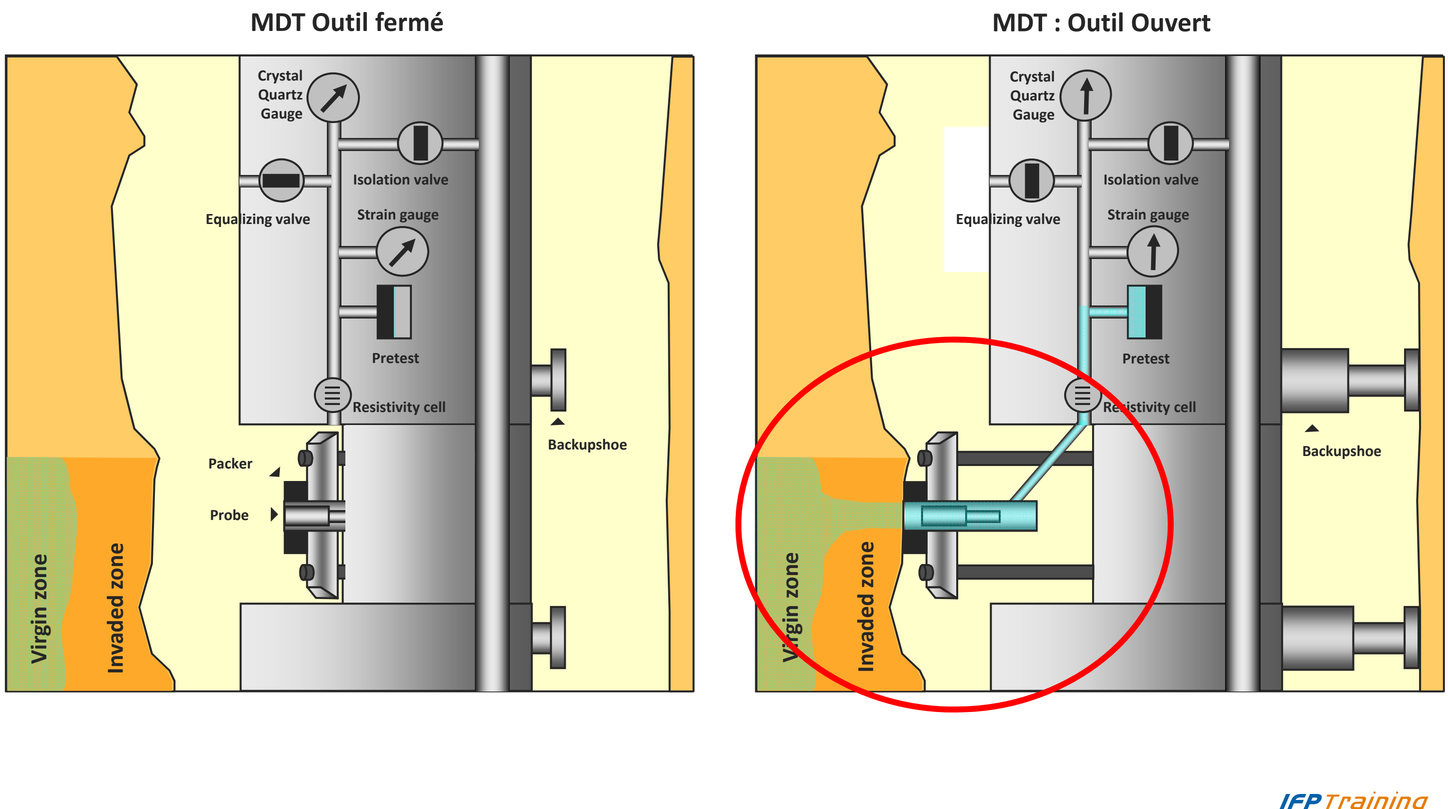
- **The formation fluid is not always homogeneous on the full height of the reservoir.**

- **Those samples are needed to:**
  - Determine the fluid type
  - Estimate hydrocarbons in place and reserves
  - Measure or estimate the fluid characteristics that will be used to design the production facilities or used in numerical models to predict the reservoir performance.

Bottom hole sampling

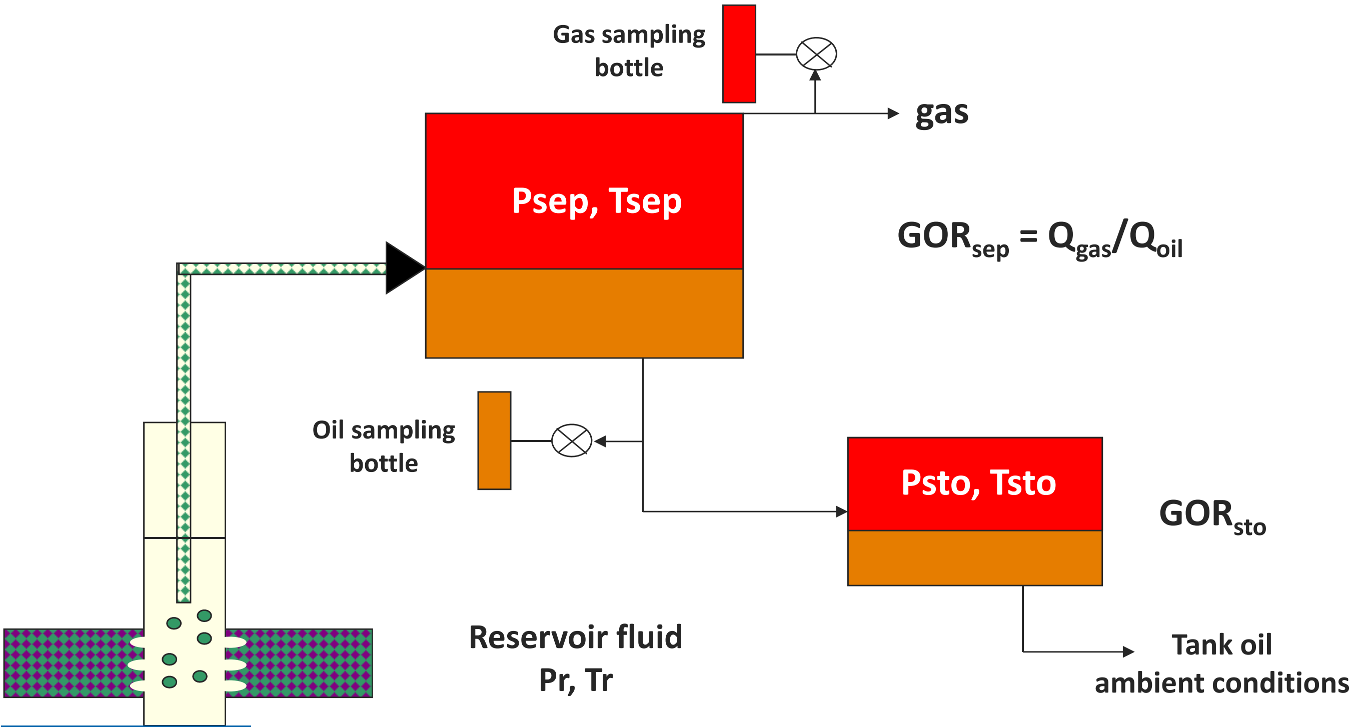
- **This type of sampling is preferred since it guarantees the best fluid representativity.**
- **One phase flow in the reservoir**
  - the reservoir fluid is undersaturated
  - bottom hole well flowing pressure is higher than bubble pressure.
- **Disadvantage: high cost**
- **Tools:**
  during drilling, various tools are used:
  - MDT (modular dynamic formation tester)
  - SRS (single phase reservoir sampler)
  - MFE (multiple flow evaluator)
  - PCT (pressure controlled test system)
  - APR (annulus pressure responsive tool)
- **To obtain a maximum bottom hole pressure :**
  - reduce the flow rate at the surface
  - sample as soon as possible during the field life

MDT operations



(from Schlumberger Document)

Surface sampling



COMMENTS

This sketch summarizes the production process between the bottom and the surface.
The reservoir fluid at reservoir temperature and reservoir pressure flows through the porous media to reach the bottom hole in front of the perforations, whose flowing pressure is lower than the reservoir pressure.
Then, the fluid flows through the tubing to the separator where the two phases are separated: oil at the bottom and gas at the top.
The gas is collected at the top of the separator and the oil is sent to the stock tank where additional gas is liberated at atmospheric temperature;
Surface sampling of the reservoir fluid is usually performed taking an oil sample at the bottom of the separator and a gas sample at the top.

Surface sampling

- **All the fluids that are collected at the well head or the production line for one phase flow (rarely), or in the separator, gas and oil, (most frequent case).**
- **Gas and oil samples collected in the separator are recombined in the laboratory in proportion to their flow rates, based on the measured gas/oil ratio, in order to recreate a reservoir fluid that will then be analyzed.**
- **Issues for good sampling:**
  - **Good accuracy** of the measured flow **rates stabilized** well production
  - Oil and gas sampling carried out almost simultaneously
  - **Total lift** of the liquid phase
  - **Separation efficiency**

Surface sampling

- **Surface sampling of an oil saturated reservoir:**
  - bottom hole flowing pressure < bubble pressure
  - liberation of gas in the reservoir should be minimized
  - gas saturation should remain below the critical gas saturation
- **Recommendations:**
  - sample the well initially
  - produce the well with small drawdown

GOR should remain constant and minimum during sampling

Notes

Sampling gas condensate reservoir

- **Bottom hole sampling is not recommended for gas condensate or wet gas**
  - The volume of fluid sampled gives a low liquid recovery and an unrepresentative heavy components analysis
  - possible segregation of the liquid at the bottom of the well
  - The liquid is not totally recovered during the transfer of bottom hole sample
- **Surface sampling**
  - sample the well initially
  - produce the well with small drawdown to minimize the formation of a condensate ring near the well bore
  - stabilize the well rate above minimum gas velocity
- **Difficulties encountered during surface sampling of gas condensate**
  - possible liquid carryover at the separator
  - compromise has to be found between a flow rate (to have FBHP> Pdew) and high flow rate (to lift the liquid condensing in the tubing)

Sampling: summary

Produced fluid	Fluid flow and Reservoir characteristics	Sampling type	
		Bottom hole sampling	Surface sampling
Undersaturated oil	GOR=GORi=Ct	Well in production with Pwf>Pb	Stabilized well with Pwf>Pb
Saturated oil	GOR > GORi Pwsi = Pb	To bean back progressively. Well closed and stabilized. Sampling at minimum flow rate.	To bean back to have GOR≈ GORi Stabilized flow rate with ΔP min
Gas	GOR=GORi=Ct	Not recommended with - separator stability	Minimum flow rate possible; Compatible - homogeneous flow in the tubing

Notes

Back-up information
Units
Some more equations

System of units used in well test analysis

Parameter	Symbol	SI-Units	Field units	Darcy Units
Flow rate	q	Sm^3/d	STB/D	cc/sec
Volume factor	B	Rm^3/Sm^3	RB/STB	rcc/cc
Thickness	h	m	ft	cm
Permeability	k	m^2	mD	Darcy
Viscosity	µ	mPa.s	cp	cp
Pressure	p	kPa	psi	atm
Density	ρ	kg/m^3	lb/cu.ft	g/cc
Radial distance	r	m	ft	cm
Compressibility	c	$(kPa)^{-1}$	psi^{-1}	atm^{-1}
Time	t	hrs	hrs	sec

1 STB/D=0.159 Sm^3/d
1 ft = 0.3048 m
1 mD = 0.987. 10^3 $(\mu m)^2$
1 cP = 1 mPa.s
1 psi = 6.895kPa = 0.06895 atm

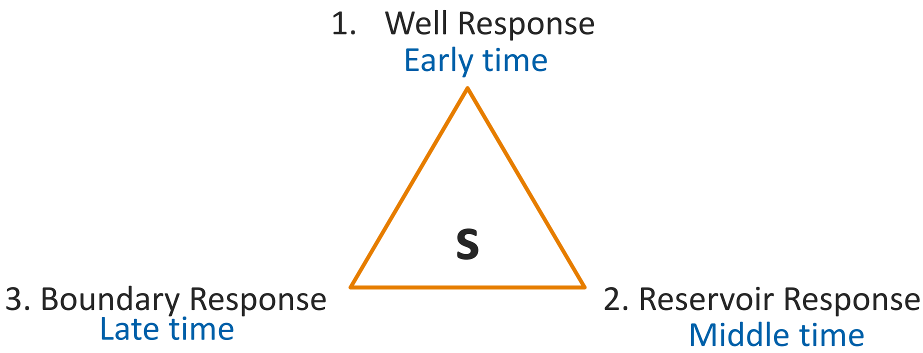
The inverse problem

- The objective of well test analysis is to describe an unknown system **S** (well + reservoir) by indirect measurement (**O** the pressure response to **I** a change of rate)

A **direct problem**: **I*S=O**

In WTA, we are solving an **inverse problem**; **S=O/I**

- A well test analysis leads to a model. A model is made of 3 chronological parts



Flow geometry

- A flow regime is the geometry of the flow streamlines in the tested formation

- Flow regime appears as a characteristic pattern (straight line) displayed by the bottom-hole pressure when plotted on a specialized plot

- For each flow regime, a set of well or reservoir parameters can be computed using only the portion of the pressure data that exhibits the characteristic pattern behavior

- The flow regimes commonly observed in well test data are wellbore storage, linear, bilinear, spherical, radial, pseudosteady state, steady state

Dimensionless variables

- Radial diffusivity equation $$\frac{\delta p}{\delta t} = 0.0002637 \frac{k}{\phi \mu c_t} \frac{1}{r}\left[\frac{\delta}{\delta r}\left(r \frac{\delta p}{\delta r}\right)\right]$$
- Dimensionless radius: $$r_D = \frac{r}{r_w}$$
- Dimensionless time: $$t_D = 0.0002637 \frac{kt}{\phi \mu c_t {r_w}^2}$$
- Dimensionless pressure (difference): $$p_D = \frac{kh}{141{,}2 qB\mu}(p_i - p)$$
- Substituting this into the radial diffusivity equation will yield an equivalent dimensionless problem: $$\boxed{\frac{\delta p_D}{\delta t_D} = \frac{1}{r_D}\left[\frac{\delta}{\delta r_D}\left(r_D \frac{\delta p_D}{\delta r_D}\right)\right]}$$

The analytical solution in an Infinite Reservoir

- **The dimensionless differential system takes the form:**
  - Diffusivity equation: $$\frac{\delta p_D}{\delta t_D} = \frac{1}{r_D}\left[\frac{\delta}{\delta r_D}\left(r_D \frac{\delta p_D}{\delta r_D}\right)\right]$$
  - Initial condition: $$p_D = 0 \qquad \text{all } r_D$$
  - Line source (Darcy equation): $$\left[r_D \frac{\delta p_D}{\delta r_D}\right]_{r_D \to 0, t} = -1$$
  - Boundary condition (infinite reservoir): $$r_D = \infty, p_D = 0 \qquad \text{all } r_D$$
- **The analytical solution of the differential system is:** $$p_D(r_D, t_D) = -\frac{1}{2}\mathrm{Ei}\left(-\frac{{r_D}^2}{4t_D}\right)$$
- The approximate solution, when, $\frac{{r_D}^2}{4t_D} < 0{,}01$, is given as: $$\boxed{p_D(r_D, t_D) = \frac{1}{2}\left[\ln\left({r_D}^2/t_D\right) + 0{,}80907\right]}$$

Thank you for your attention!